ELECTROMAGNETIC HEATING OF UNCONVENTIONAL HYDROCARBON

RESOURCES ON THE ALASKA NORTH SLOPE

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A

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ABSTRACT

The heavy oil reserves on the Alaska North Slope (ANS) amount to approximately 24-33 billion barrels and approximately 85 trillion cubic feet of technically recoverable gas from gas hydrate deposits. Various mechanisms have been studied for production of these resources, the major one being the injection of heat into the reservoir in the form of steam or hot water. In the case of heavy oil reservoirs, heat reduces the viscosity of heavy oil and makes it flow more easily. Heating dissociates gas hydrates thereby releasing gas. But injecting steam or hot water as a mechanism of heating has its own limitations on the North Slope due to the presence of continuous permafrost and the footprint of facilities. The optimum way to inject heat would be to generate it in-situ.

This work focuses on the use of electrical energy for heating and producing hydrocarbons from these reservoirs. Heating with electrical energy has two variants: high frequency electromagnetic (EM) heating and low frequency resistive heating. Using COMSOL™ multi-physics software and hypothetical reservoir, rock, and fluid properties an axisymmetric 2D model was built to study the effect of high frequency electromagnetic waves on the production of heavy oil. The results were encouraging and showed that with the use of EM heating, oil production rate increases by ~340% by the end of third year of heating for a reservoir initially at a temperature of 120°F. Applied Frequency and input power were important factors that affected EM heating. The optimum combination of power and frequency was found to be 70 KW and 915 MHz for a reservoir initially at a temperature of 120°F. Then using CMG-STARS™ software simulator, the use of low frequency resistive heating was implemented in the gas hydrate model in which gas production was modeled using the depressurization technique. The addition of electrical heating inhibited near-wellbore hydrate reformation preventing choking of the production well which improved gas production substantially.

DEDICATION

I dedicate this thesis to the Almighty *Sai Baba*

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1. INTRODUCTION

The Alaska North Slope (ANS) is home to various heavy oil reservoirs, the major ones being Schrader Bluff/West Sak and Ugnu, which jointly contain approximately 24–33 billion barrels of oil (Pospisil, 2011) (Figure 1.1). According to an assessment by the U.S. Geological Survey (USGS, 2008), ANS also contains an estimated 85.4 trillion cubic feet of undiscovered, technically recoverable gas from natural gas hydrates (Figure 1.2).

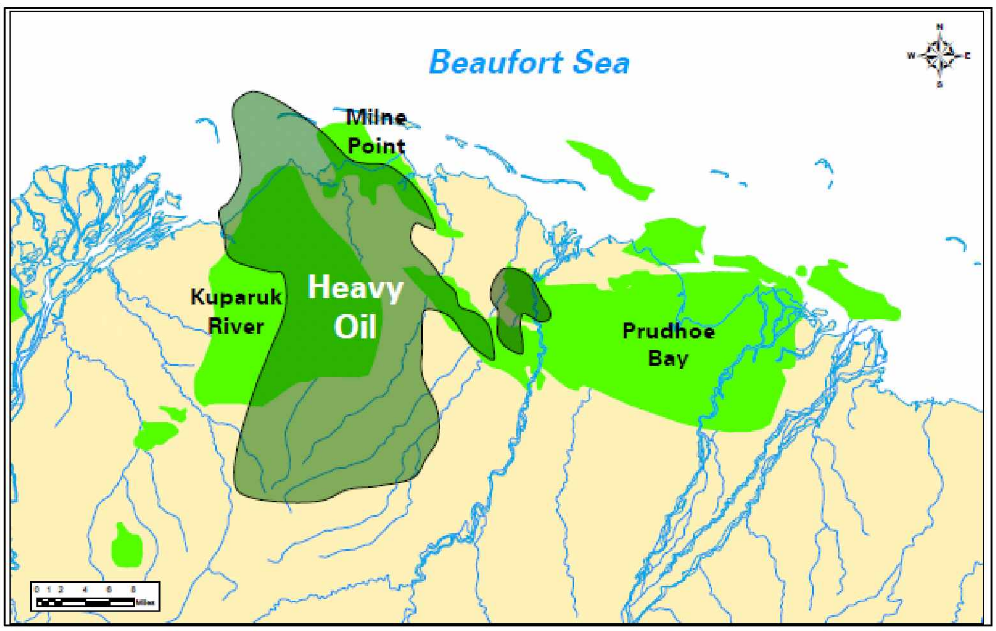

Figure 1.1: Heavy Oil Distribution on Alaska North Slope

(Pospisil, 2011)

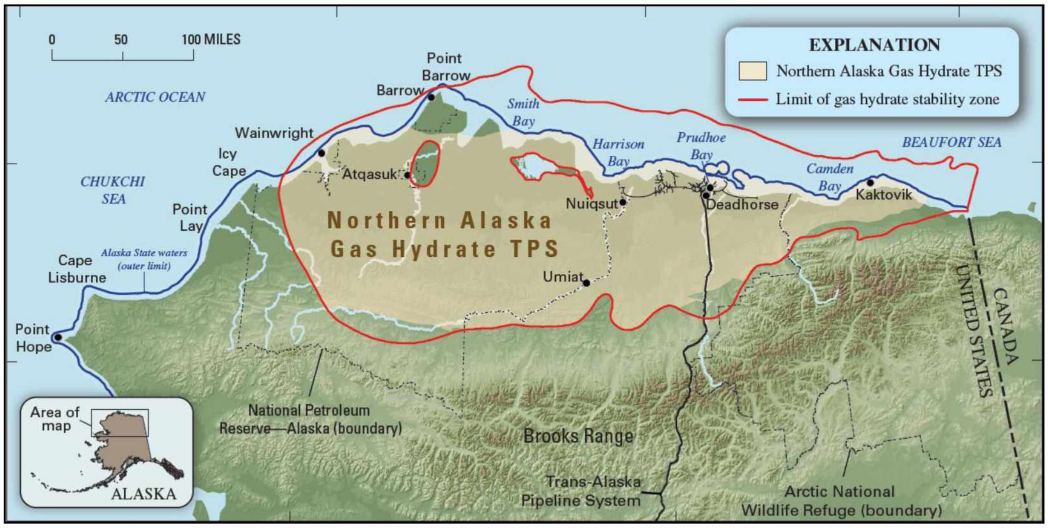

Figure 1.2: Gas Hydrate Resource Distribution on Alaska North Slope

(USGS Fact Sheet, 2008)

Producing from unconventional heavy oil reservoirs is challenging in the Arctic. The viscosity of oil in such heavy oil reservoirs is so high that primary or even secondary recovery methods are inefficient (Green and Willhite, 1998). Hence various enhanced oil recovery (EOR) processes are used to produce from these heavy oil reservoirs. These EOR processes can be divided into two categories – chemical and thermal (Green and Willhite, 1998). Miscible gas injection, alkaline flooding, and polymer flooding are a few of the chemical processes that react chemically with the oil, either reducing the interfacial tension in the reservoir as in the case of alkaline flooding or increasing the vertical sweep in the case of polymer flooding (Green and Willhite, 1998). Thermal EOR methods inject heat into the reservoir. Since viscosity is a strong function of temperature, as the temperature of the reservoir increases, the viscosity of the oil decreases. The oil flows more easily and can be more efficiently produced. For example, an increase in temperature from 68ºF (20ºC) to 167ºF (75ºC) reduces the viscosity of Arabian light crude oil by a factor of 3.This reduction is by a factor of 30 and 1000, respectively, for 15^{o}API Lloydminster heavy oil and 8^{o}API Athabasca extra heavy oil (Tissot and Welte, 1984). Thermal methods for EOR have been very successful in producing from these heavy oil reservoirs (Green and Willhite, 1998). Thermal recovery methods are the most advanced EOR processes and contribute significant amounts of oil to daily production (Green and Willhite, 1998).

Thermal recovery processes are based on the principle that viscosity decreases as temperature increases. Heating the reservoir is the fundamental fact underlying thermal processes (Green and Willhite, 1998). Thermal methods for EOR include cyclic steam injection, hot water flooding, and in-situ combustion. Of all thermal methods, steam injection has proved most successful. In 1993, CSS and steam-drive methods accounted for the production of more than 700,000 bbl/day of oil worldwide (Green and Willhite, 1998).

But conventional methods of thermal recovery, even with the use of insulated tubing, have high heat loss associated with them when applied in arctic conditions, mainly due to the presence of a thick layer of permafrost, as is the case with the Alaska North Slope (Islam and Chilingarian, 1995). Steam injection may result in thawing of the permafrost if injected from the surface and may lead to loss of surface production facilities due to subsidence or to casing failures caused by casing strain (Olsen et al., 1992). If steam is injected at the surface, extensive insulation of the tubing would be required to prevent thawing of the surrounding permafrost (Olsen et al., 1992). Hallam et al. (1992) showed that with the use of cyclic steam injection with a well-insulated casing, by the third year the thaw radius was approximately 10 ft at the sand face and 1 ft at the surface. In such cases a downhole heating device seems attractive and an efficient process to recover hydrocarbons from such reservoirs. Also in reservoirs that have high permeability heterogeneity, conventional thermal methods such as steam injection prove inefficient due to non-uniform heating of the zone and gravity segregation effects; plus there is a significant heat loss to the overburden and under-burden (Sahni et al., 2000).

Various mechanisms have been studied for the production of gas from gas hydrates. The three most commonly discussed methods are depressurization, thermal stimulation, and inhibitor injection (Islam, 1991; Castaldi et al., 2007; Kamath and Godbole, 1987). Depressurization technique has shown promise in producing from hydrate reservoirs, but this technique suffers from the disadvantage that the dissociation of hydrates is an endothermic reaction; this method might potentially result in the reformation of hydrates (Castaldi et al., 2007) as reservoir rock cools. To produce from gas hydrate reservoirs, the addition of heat can be critical to keep the reservoir temperature above the hydrate reformation temperature and accelerate gas production.

To overcome the disadvantages of conventional thermal methods for EOR and gas hydrate dissociation, researchers have considered in-situ heating of the reservoir. One method studied for quite some time now is the electrical heating of reservoirs, using electrical energy to heat the formation (Fanchi, 1990; Chakma and Jha, 1992; Soliman, 1997; Sahni et al., 2000; McGee and Vermeulen, 2000). The use of electrical energy for heating can be divided into two categories:

1. Electromagnetic (EM) heating is a phenomenon in which the formation is irradiated with high frequency waves, generally in the range of MHz and GHz with the help of a downhole antenna (Chakma and Jha, 1992; Sahni et al., 2000; Shuanshi et al., 2004). The formation and the fluids present pose a resistance to the flow of these waves which results in the generation of heat. Since the frequency of these waves is high, their wavelengths are short. Only the area in the vicinity of the antenna is heated. This heat is transferred to the surrounding areas by conduction and convection and ultimately results in a rise in temperature that causes lowering of the viscosity of heavy oil. In case of gas hydrate formation, this rise in temperature dissociates the hydrates and releases the trapped gas.
2. Low frequency electrical heating uses frequencies up to 300 Hz (Pizarro and Trevisan, 1990). In this method, electrodes are placed in the formation and an electric potential is applied. As a result, electric current is generated in the formation and flows through the fluids present in the formation (McGee and Vermeulen, 2000; Bogdanov et al., 2008). As these fluids have resistance, heat that is proportional to the

square of free current density and the resistance of the material through which the current is flowing is generated (Carrizales, 2010; McGee and Vermeulen, 2000; Bogdanov et al., 2008). As compared to EM heating, a much larger area is heated with the use of low frequency electrical heating but the intensity is less (Bogdanov et al., 2008).

1.1 Research Objectives

The main objective of this research was to study the application of EM heating for heavy oil recovery and methane hydrate dissociation, and how the application of EM heating coupled with fluid flow can be used to increase productivity from these heavy oil reservoirs. The application of low frequency resistive heating to dissociate methane hydrate to produce gas in conjunction with depressurization technique was also investigated. This research has been divided into two parts:

1.1.1 To Study the Effect of EM Heating on Heavy Oil Recovery

- Develop a two–dimensional EM heating model coupled with a single phase flow using COMSOL multi-physics to simulate and study the effect of EM heating on heavy oil recovery.
- Modeling improvement in oil productivity achieved by EM heating of heavy oil reservoirs.
- Assess important variables that affect EM heating such as EM frequency, power input, and reservoir temperature, and conduct a sensitivity analysis.
- Build a Cyclic Steam Stimulation (CSS) model using CMG-STARS, and compare the results with EM heating.

1.1.2 To Study Low Frequency Electrical Heating for Gas Hydrate Dissociation

- Using the electrical heating application in the CMG-STARS commercial reservoir simulator, study the effect of low frequency electrical heating on the gas hydrate model developed by Novruzaliyev (2011).
- Modeling improvement in gas production due to electrical heating in combination with the depressurization technique.

1.2 Research Methodology

To meet the above–mentioned objectives, work was carried out in different stages. In the first stage the use of EM heating for heavy oil recovery was considered. Using COMSOL multi-physics software, a two–dimensional reservoir model was built in cylindrical coordinates with the antenna placed at the production well as shown in Figure 1.3. To model the heating due to EM waves, a 2-D axisymmetric model of the reservoir was made and therefore only one half of the reservoir was modeled keeping the antenna on the axis of symmetry. The absorption coefficient, which is a function of temperature, was assumed to remain constant throughout this research work. Heat loss to the overburden and under–burden was not considered, and no flow was considered in the vertical direction.

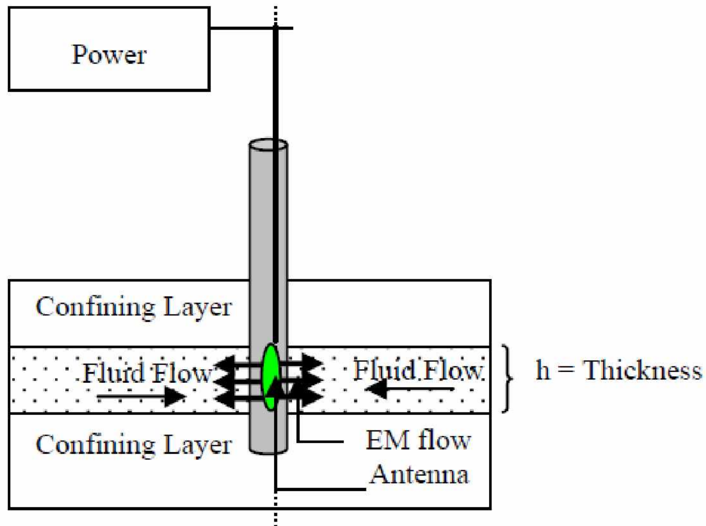

Figure 1.3: Electromagnetic Heating Schematic
(Carrizales, 2010)

In the second stage, the effect of electrical heating on gas hydrate dissociation was studied using the CMG-STARS reservoir simulator. Novruzaliyev (2011) built a gas hydrate model to study the effect of depressurization technique on the production of gas from a hydrate reservoir. Electrical heating was added to the depressurization model. This model was then used to study the increase in gas production that can be achieved with the addition of electrical heating, over gas production due to depressurization alone.

2. LITERATURE REVIEW

2.1 Types of Electrical Heating Methods

Electrical energy can be used to heat the formation by two methods that differ in the range of frequencies used (McGee and Vermeulen, 2000). One method is low frequency resistive heating, also known as electrical resistive heating (ERH). The other is high frequency EM heating due to EM power absorption. The main objective of both methods is to heat the formation to increase reservoir temperature, thus aiding heavy oil production or hydrate dissociation.

The electrical properties that are important and govern the heating are different for each method. For ERH the electrical properties of prime importance are the applied voltage, current density, and electrical conductivity. For EM heating the properties to be considered are the permittivity, magnetic permeability, electrical conductivity, and input power used.

2.1.1 Low Frequency Resistive Heating

In this mode of electrical heating, electrodes are placed in the formation and an electric potential is applied across them (McGee and Vermeulen, 2000). The electrode design is shown in Figure 2.1. Due to this potential gradient, an electric current is developed in the formation. The generated electric current passes through the connate water present in the formation that has electrical resistance associated with it (Figure 2.2). When the current passes through this resistive element, heat is generated due to ohmic losses (Carrizales, 2010; McGee and Vermeulen, 2000). For this type of heating, the presence of water is necessary. It should not be allowed to evaporate due to continuous heating since this would break the conductive path for the electric current (Baylor et al., 1990). The volumetric heating rate that is developed is calculated using Equation 2.1

$$Q = R\bar{J}^2 \tag{2.1}$$

Where R is the resistance of the element through which the current passes and J is the free current density (Carrizales, 2010). The depth of heat penetration is much more in case of low frequency heating than high frequency EM heating but the intensity is less causing a lower temperature rise (Carrizales, 2010). The advantage compared to conventional methods is that heat is generated in-situ so heat losses are reduced (Chakma and Jha, 1992; Sahni et al., 2000). Also it is environmentally friendly as small wells are required for electrodes keeping the rest of the land undisturbed (Wells, 2007).

Figure 2.1: Electrode Design for Low Frequency Electrical Heating (Wells, 2007)

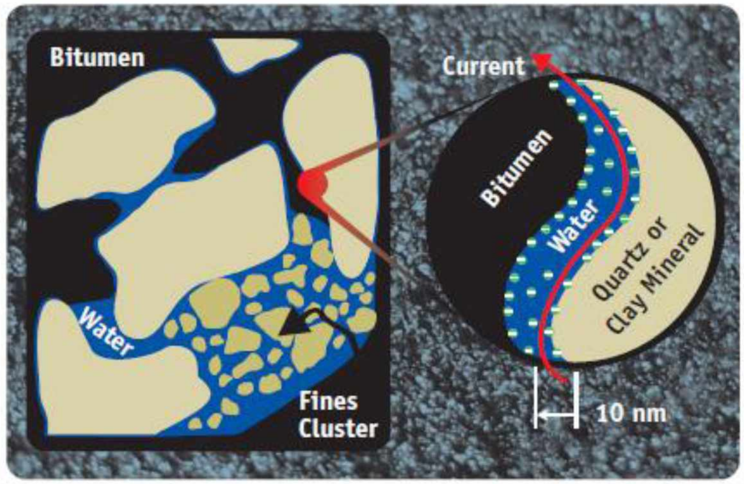

Figure 2.2: Mechanism of Heat Generation by Low Frequency Electrical Heating

(Wells, 2007)

2.1.2 Electromagnetic Heating Using High Frequency Waves

Microwaves are EM waves with frequency in the range of 300 MHz to 300 GHz and wavelengths ranging from one meter to as short as one millimeter, as shown in Figure 2.3. Dielectric heating is the process by which EM radiation heats a dielectric material (Dong-Liang et al., 2008). This heating is caused by dipole rotation (Pizarro and Trevisan, 1990; Dong-Liang et al., 2008), as shown in Figure 2.4. In conventional heat transfer processes, heat is transferred to the material through conduction, convection, or radiation due to the difference in temperatures (Dong-Liang et al., 2008). Microwaves interact well with dipoles, such as water. Microwaves generate rapidly changing electric fields, and dipoles rapidly change their orientations in response to the changing fields (Pizarro and Trevisan, 1990).

The polar molecules having a dipole moment try to align themselves in an EM field (Fanchi, 1990). If the electric field is oscillating, then the molecules rotate continuously to align with it. This phenomenon is called dipole rotation. As the field is alternating, the molecules reverse direction. The rotating molecules push and collide with the neighboring molecules distributing the energy to adjacent molecules and atoms. Agitating the molecules in this way increases the temperature of the material (Fanchi, 1990). Dielectric heating generates heat throughout the volume of the material (Dong-Liang et al., 2008), as shown in Figure 2.5.

In this method a microwave antenna is lowered into the reservoir and the reservoir is irradiated with high frequency high power EM waves generated on the surface and transmitted downhole through a wave guide (Fanchi, 1990; McGee and Vermeulen, 2000; Carrizales, 2010). Since these high frequency EM waves are not affected by the permeability of the reservoir and only depend on electrical and magnetic properties, they are absorbed by both the formation and the fluids that exist in the formation, depending on their electrical properties (Sahni et al., 2000).

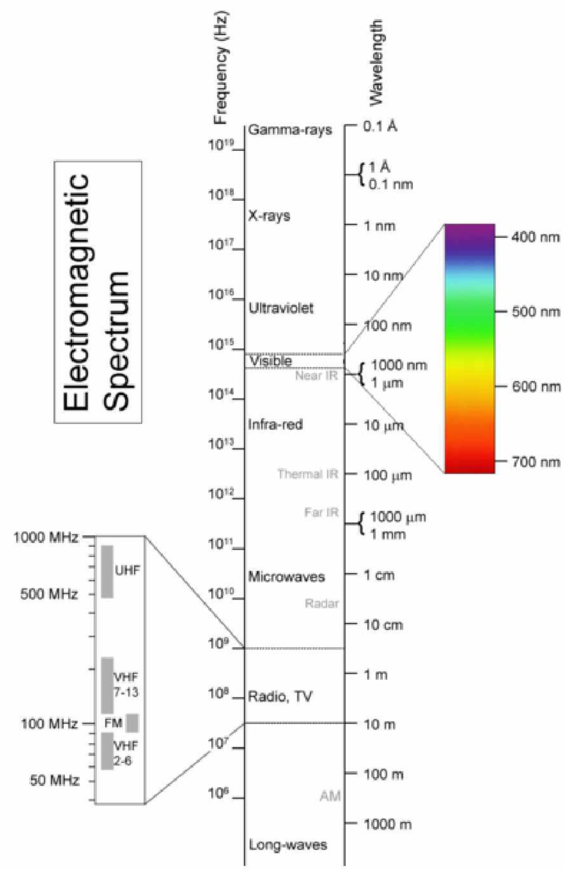

Figure 2.3: Electromagnetic Spectrum

(Wikipedia, http://en.wikipedia.org/wiki/Electromagnetic_spectrum)

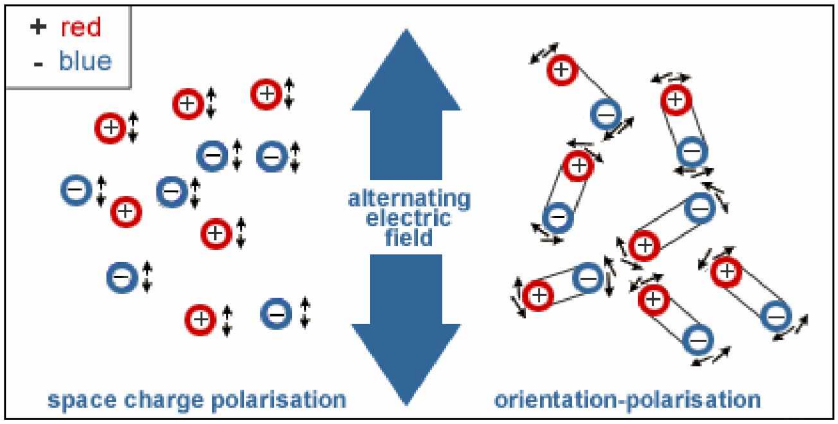

Figure 2.4: Mechanism of Dielectric Heating

(Puschner Microwave Power Systems, www.pueschner.com/basics/phys_basics_en.php)

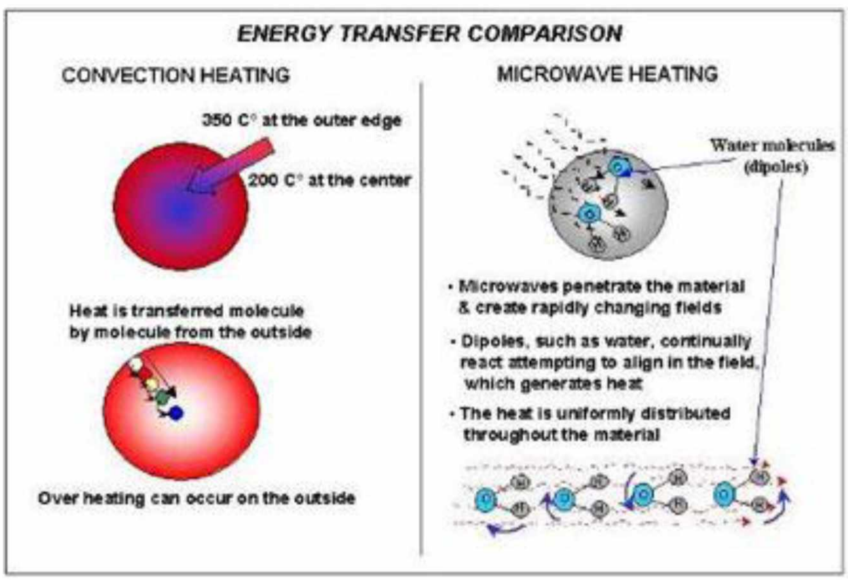

Figure 2.5: Microwave Heating Against Conventional Heating Methods

(Environmental Waste International, ewi.ca/technology/microwave-information.htm)

The main advantage of this method over steam injection is that heat can be confined to the area of interest and controlled easily from the surface. In addition, heat losses are reduced and surface infrastructure and footprint are smaller as compared to those from steam injection methods. Gravity has no effect on these microwaves and hence uniform heating of the formation can be achieved (Chakma and Jha, 1992; Sahni et al., 2000). Since the frequency of these waves is high, in the range of MHz and GHz their wavelengths are short. Only the area in the vicinity of the antenna is heated.

2.2 Important Electrical Properties of Fluids and Formation

Characteristics that play a key role when using electrical energy to heat the formation are the electrical properties of the formation and the liquid phases present in it (Carrizales, 2010). As stated earlier, the electrical properties that are important when heating using EM waves are the electrical conductivity, electrical permittivity, and magnetic permeability. These properties determine the absorption of EM waves and the generation of heat energy. Together these electrical parameters are used to calculate the absorption coefficient that determines the heating rate (Carrizales, 2010). These dielectric properties can be measured in the laboratory and are a function of frequency and temperature. The variation of these parameters with frequency and temperature was measured in the laboratory by Kasevich et al. (1994) and that work can be referred to for additional details. For this work the absorption coefficient that is a function of permittivity, magnetic permeability, and electrical conductivity is assumed to be constant and to not change with temperature.

2.2.1 Complex Magnetic Permeability ($\mathbf{M_p}$)

Since oil is not a magnetic material and does not exhibit magnetic properties when placed in a magnetic field, it is assumed that the permeability of oil is the same as the permeability of vacuum which is $M_p = 4\pi * 10^{-7}$Henry/meter (Carrizales, 2010; Kim, 1987; Chute et al., 1979). Magnetic permeability is generally denoted by μ_o, but since oil viscosity is denoted by the same Greek letter μ, for convenience magnetic permeability for this work is denoted by M_p.

2.2.2 Complex Permittivity (ε)

Permittivity is the ability of a material to transmit an electric field. It is also defined as the material's ability to polarize in response to the field and thereby reduce the total electric field inside the material (Vralstad et al., 2009). In short it is the resistance offered by a material in response to an electric field inside it. In SI units, permittivity ε is measured in Farads per meter (F/m). The effective permittivity is given by Equation 2.2.

$$\varepsilon = \varepsilon_r \varepsilon_o \tag{2.2}$$

Where, ε_r is the relative permittivity of the material and ε_o is the permittivity of vacuum which is 8.845… $\times 10^{-12}$ F/m (Carrizales, 2010).

At high frequencies molecules in a polar dielectric are polarized by an applied electric field. This causes them to rotate periodically. For example, at the microwave frequency the microwave field causes periodic rotation of water molecules, sufficient to break hydrogen bonds. The field does work against the bonds, and the energy is absorbed by the material as heat (Vralstad et al., 2009). This is why microwave ovens work well for materials containing water.

The response of a normal material to an applied external field depends on the frequency of the field. When an electric field is applied across a material, the polar molecules do not respond instantaneously to the applied field. There is a time lag and the response arises after the applied field. This can be represented by a phase difference (Vralstad et al., 2009). This phase difference is the reason why permittivity is treated as a complex function of the angular frequency of the applied electric field. Since it is a complex quantity, it has a real and an imaginary part associated with it. The real part of the permittivity is ε', which is related to the stored energy within the medium. The imaginary part of the permittivity is ε'', which is related to the dissipation (or loss) of energy within the medium.

2.2.3 Electrical Conductivity (σ)

Electrical conductivity of a material is its ability to conduct an electric current when an electric potential is applied across it. Electrical conductivity of any formation is a function of temperature, saturation distribution, and lithology (Carrizales, 2010). For the variation of electrical conductivity with frequency and temperature, refer to the work of Carrizales (2010). For this work, electrical conductivity is assumed to remain constant with temperature.

2.2.4 Absorption Coefficient (α)

The absorption coefficient or attenuation coefficient is the attenuation in an EM wave per unit distance as it passes through a medium (Fanchi, 1990; Carrizales, 2010). It is denoted by the Greek letter alpha (α) and its SI unit is per meter. The larger the value of this absorption coefficient, the lesser the penetration of the wave will be in that medium. The absorption coefficient is given by Equation 2.3 as

$$\alpha = \omega\sqrt{\frac{\varepsilon M_P'}{2}}\left[\sqrt{1+\left(\frac{\sigma}{\varepsilon\omega}\right)^2}-1\right]^{1/2} \tag{2.3}$$

where, α is the absorption coefficient, ω is 2π times the applied frequency, ε is the real part of the complex permittivity, σ is the electric conductivity, and M_P' is the real part of the complex magnetic permeability of the medium (Fanchi, 1990; Carrizales , 2010). The absorption coefficient is a function of both frequency and temperature. The variation of α with frequency and temperature can be found in the literature (Carrizales, 2010). For this work the variation of α with frequency is considered, whereas it is assumed to remain constant with temperature. The variation of α with frequency is given in Table 2.1.

Table 2.1 Variation of absorption coefficient α with frequency measured at a temperature of 100^0F obtained from Equation 2.2 (Carrizales, 2010)

Frequency (MHz)	α (1/m)
13.54	0.0073
27	0.0117
50	0.0173
140.6	0.0364
163	0.0433
381	0.0693
915	0.1322
2450	0.2604

2.3 Physical Properties of Oil

Rock and fluid properties affect the way the reservoir behaves. Of these properties there are a selected few that are of importance when the reservoir is heated using EM waves. These properties are discussed in the following sections.

2.3.1 Oil Viscosity

Viscosity of oil is a function of temperature. It decreases as the temperature increases. This temperature dependence of viscosity has been represented by various empirical relations. For this research work the empirical relation used by Carrizales and Lake (2009) is used, which is given by Equation 2.4 as

$$\mu\,(z) = De^{F/T(z)} \tag{2.4}$$

In Equation 2.4, D and F are constants with D measured in Pa*sand T measured in K. By measuring the viscosity of crude oil at two different temperatures and calculating, these constants can be determined. Values of empirical constants D and F to calculate viscosity at different temperatures for this work are 4.89E-11 Pa*s and 8006 K, respectively.

2.3.2 Heat Capacity

Values of heat capacity for oil and formation found in the literature have been used for this research work (Kamath and Godbole, 1987).

2.3.3 Thermal Conductivity

Thermal conductivity of the formation is an important factor that affects heat propagation in a reservoir in cases of EM heating. As mentioned earlier, the frequency of the waves is high in the range of MHz and GHz; thereby their wavelength is very short. With the use of these high frequencies only a portion near the wellbore is heated. But due to thermal conductivity of the formation and fluids present and the temperature difference near the wellbore and deep formations, this heat is propagated more deeply into the formation, thereby increasing the area affected by EM heating. Thermal conductivity is a function of temperature, but in this work it is assumed to remain constant with temperature. The values' of thermal conductivity for the crude and the formation have been taken from literature (Kamath and Godbole, 1987).

2.4 Previous Work Described in Literature

The Illinois Institute of Technology Research Institute (IITRI) of Chicago, Illinois, conducted a field test in the Lloydminster Sand in the Wildmere Field, Alberta. Due to EM heating, the oil production rate increased from 6 to 20 bbl/day after a period of 20 days (Carrizales, 2010). The IITRI also conducted a well test near Ardmore, Oklahoma. With an input power of 40 KW and a frequency of 6.78 MHz, the temperature near the antenna increased to about 212°F (100°C) from an initial temperature of 64°F (18°C). At a distance of 4.5 ft from the antenna, the temperature increased to 149°F (65°C) and at a distance of 15 ft the recorded temperature was 91°F (33°C) (Baudrand et al., 1997).

Pizarro and Trevisan (1990) presented the field test results of low frequency electrical heating of the Rio Panom field in Brazil. The initial oil viscosity was high in the range of 2,500 cp. After 70 days of electrical heating with an input power of 30 KW, the oil production was increased from 1.2 bbl/day to 13 bbl/day.

Chakma and Jha (1992) combined EM heating with gas injection (nitrogen). With gas injection alone the recovery was in the range of 20% OOIP. With the use of EM heating as a stand-alone process, the recovery was about 24% OOIP. But with gas injection and EM heating combined, the recovery increased to 45% OOIP, due to the combined effects of viscosity reduction and oil mobilization.

Soliman (1997) showed that with the use of EM heating with an input power of 100 KW, oil production can be improved by a factor of two. This increase in production is directly attributed to the reduction in oil viscosity due to continuous heating.

Sahni et al. (2000) studied the use of EM heating for EOR and showed that with the use of a 60 KW microwave source, the temperature after a year of heating increases to 300ºF from an initial temperature of 100ºF. With the use of two EM sources, the cumulative oil production can be increased up to 80% compared to the primary production. They also performed simulations on the use of low frequency electrical heating for heavy oil production using two horizontal electrodes. The applied voltage was 300 V at a frequency of 60 Hz. After 6 months of heating, the temperature near the electrodes increased to 300ºF.

Davletbaev (2007) showed that for oils at a lower viscosity, EM heating alone can be used for production. But for oil with higher initial viscosity, the process becomes more efficient if a solvent is injected simultaneously with the heating process.

3. EM HEATING RESERVOIR MODEL

3.1 EM Heating Source

EM waves attenuate when applied through a medium that has a relative permittivity value associated with it. This attenuation in EM waves in turn heats the medium depending upon EM absorption properties (Fanchi, 1990). The EM waves when applied exert torque on the polar molecules. The alternating electric field causes them to align with the changing polarity, creating friction that results in the development of heat (Fanchi, 1990). This EM source can be converted into a heat source using equations which are a function of power and the absorption coefficient. Many researchers have shown that this heat source term due to EM heating can be mathematically derived from the solution of Maxwell's equation (Fanchi, 1990; Carrizales, 2010). Following the work of Fanchi (1990) and Carrizales (2010) the EM heating source term can be expressed as in Equation 3.1.

$$q_{em} = \alpha \frac{P_0 e^{-\alpha(r-r_w)}}{r} \tag{3.1}$$

Where, q_{em} is the heating developed due to EM waves,P_0 is the EM power,α is the absorption coefficient, r is the radial distance increasing away from the wellbore, and r_w is the radius of the wellbore.

Sahni et al. (2000) have suggested that the EM power at any point is also a function of the absorption coefficient as described in Equation 3.2.

$$P_i^k = \frac{2P_o^k\alpha^2}{V}\left(\frac{1}{(2\alpha^2)} - \left(r^2 + \frac{r}{\alpha} + \frac{1}{2\alpha^2}\right)e^{-2\alpha r}\right) \tag{3.2}$$

Where

α = attenuation of grid block i

r = equivalent radius of grid block i

P_i^k = energy absorbed by grid block i due to the k[th] point source (which is block i)

P_o^k = antenna power for the k[th] point source in the linear array

V = volume of grid block i

Substituting P_i^k for P_0 in Equation 3.1 and replacing the volume of the reservoir block by the external radius (r_e) for application in 2D, we can get the modified EM heating source term as shown in Equation 3.3.

$$q_{em} = \alpha \frac{\frac{2P_O\alpha^2}{r_e}\left(\frac{1}{(2\alpha^2)} - \left(r^2 + \frac{r}{\alpha} + \frac{1}{2\alpha^2}\right)e^{-2\alpha r}\right)e^{-\alpha(r-r_w)}}{r} \tag{3.3}$$

3.2 Boundary Conditions

To solve fluid flow equations and heat transfer equations, the model requires us to input the initial boundary conditions. For simulating fluid flow we need to define the pressures at all boundaries. In solving for heat transfer we need to define the temperature at the boundaries.

The pressure (P_e) at the external boundary (r_e) is assumed to be constant and equal to the initial reservoir pressure. The pressure at the wellbore, the flowing bottom hole pressure (P_{wf}), is also kept constant throughout the simulation. A no-flow boundary condition is imposed on all other boundaries, and fluid flow is only in the horizontal direction with the fluids flowing without slipping on the boundaries.

To solve the temperature equation, the boundary temperatures are kept constant equal to the initial reservoir temperature. The EM heating source is placed on the axis of symmetry. Heat loss to the overburden and under-burden is neglected.

3.3 Development of Two Dimensional EM Heating Model Using COMSOL

COMSOL multi-physics software is a licensed product with the capability to combine and solve for various physics in which the variables are linked through equations and specification of the boundary conditions. To solve for these physics, COMSOL uses the finite element method.

To develop the 2D EM heating model from the Earth Science module of COMSOL, heat transfer due to conduction in porous media was selected to solve for the heating of the formation. To solve for the fluid flow and pressure, Darcy's law was used.

COMSOL supports including user partial differential equations (PDEs) to solve for temperature and fluid flow. This research work focuses on using available components from the Earth Science module. However, if we need to simulate complex multiphase phenomena, the available modules are insufficient and one needs to develop and use PDEs. For this research work the built-in PDE's from the Earth Science module were used.

4. TWO-DIMENSIONAL EM HEATING MODEL FOR HEAVY OIL RECOVERY

4.1 Description of the Model

A 2D axisymmetric reservoir model (Figure 4.1) was built with literature available data for North Slope heavy oil reservoirs and pressure and temperature conditions that are listed in Table 4.1. The density of the oil is 58 lbm./ft^3 (20 °API) at reservoir conditions. The values of the empirical constants D and F to calculate viscosity at different temperatures are 4.89E-11 Pa*s and 8006 K, respectively. Using these values, the viscosity of the oil at initial reservoir temperature of 120°F is 3062 cp (3.062 Pa*s; 1 Pa*s = 1000 cp). Using the multi-physics option, heat transfer due to conduction in porous media and Darcy's law were combined to do the analysis. Time periods were set as 1 year and 3 years during which the heating and resulting temperature rise of the near wellbore, the reduction in the viscosity, and the change in the production rate were studied.

The presence of connate water and gas poses a complex multiphase problem when EM heating is applied. Due to continuous heating, the reservoir temperature increases over the boiling temperature of water and converts connate water into steam that will move in the reservoir and transfer heat due to convection. In addition, the vaporization of water creates a dry zone (Kim, 1987; Carrizales, 2010) through which EM waves can pass without attenuating. This is a very complex phenomenon to model and requires complex phase change equations in COMSOL. To reduce the complexity of the simulation, the pores are assumed to be saturated with oil with no connate water, and the oil is assumed to be dead oil with no dissolved gas.

Table 4.1 Reservoir and fluid properties used for EM heating model

Property	Value
Reservoir Thickness, ft	100
Initial Reservoir Pressure, psi	1300
Initial Reservoir Temperature, ºF	120
Pressure at the Outer Boundary, psi	1300
Flowing Bottom Hole Pressure, psi	600
Wellbore Radius, ft	0.3
Density of Oil, lbm./ft^3	58
Viscosity of Oil, cp	3062
Porosity	0.3
Permeability, mD	1000
Compressibility of Oil, psi^{-1}	1.50E-05
Empirical Constant D, Pa*s	4.89E-11
Empirical Constant F, K	8006
Power Input, W	70,000
Frequency Used, MHz	915
Absorption Coefficient, 1/m	0.1322

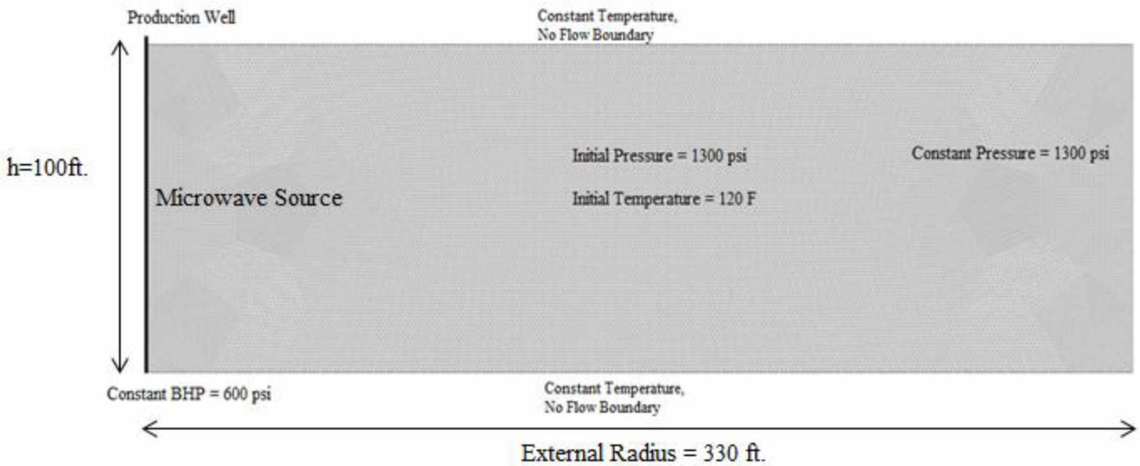

Figure 4.1: Axisymmetric 2D Model for EM Heating Using COMSOL

Using the correlation presented in Equation 2.4 with the values of D and F as 4.89E-11 Pa*s and 8006 K, respectively, the variation of viscosity with temperature was calculated at atmospheric pressure (Figure 4.2).

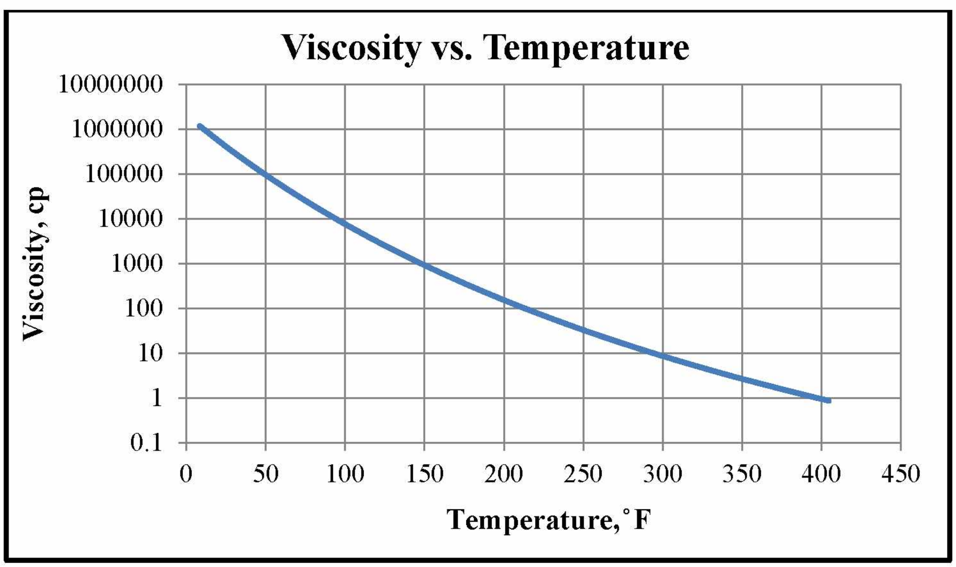

Figure 4.2: Variation of Viscosity with Temperature

4.2 Results and Discussion

4.2.1 After 1 Year of EM Heating

After 1 year of EM heating, the temperature near the wellbore rises to 212ºF from an initial reservoir temperature of 120ºF, a 76% increase in reservoir temperature. The temperature at a distance of 33 ft (10 m) from the wellbore increases to 141ºF, a 17% increase in the reservoir temperature, as shown in Figure 4.3.

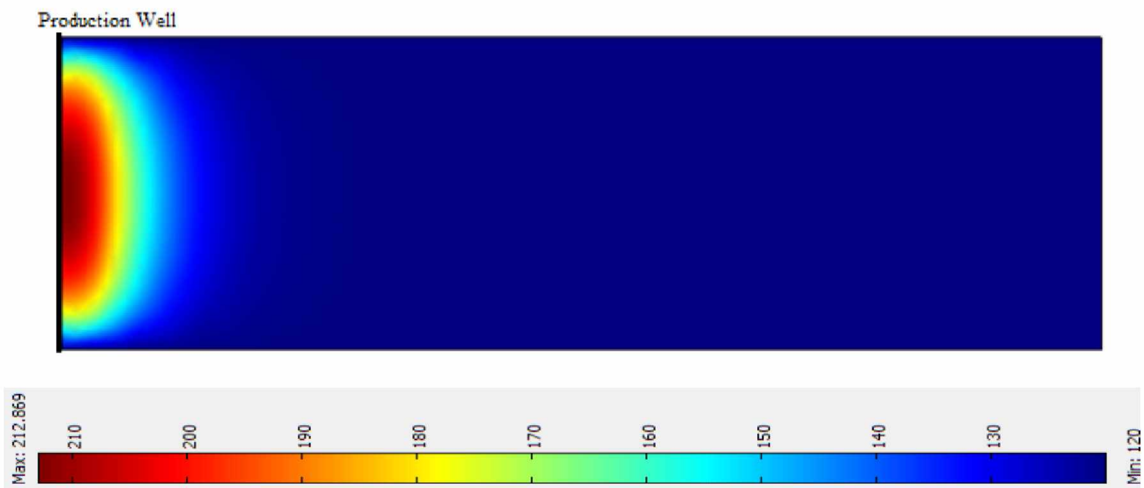

Figure 4.3: Temperature (ºF) Profile after 1 Year of EM Heating

As the temperature of the near wellbore rises, the viscosity of the fluids in contact reduces. The viscosity of the oil reduces from initial viscosity of 3062 cp (3.062 Pa*s) to 98.9 cp (0.0989 Pa*s), a 97% reduction. The viscosity profile after 3 years of EM heating is shown in Figure 4.4.

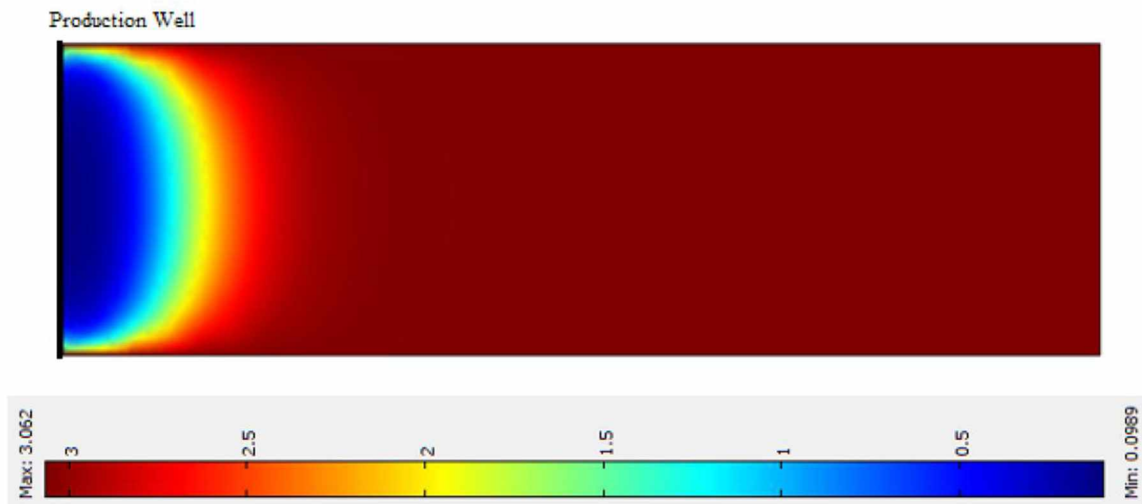

Figure 4.4: Viscosity Profile in Pa*s (1Pa*s = 1000 cp) after 1 Year of EM Heating

Figure 4.5 depicts the production profile from this reservoir after 1 year of EM heating and comparison between production with and without EM heating. The production rate without any heating is 19 bbl/day. Production rate increases to 71 bbl/day at the end of first year due to continuous EM heating, an increase of 273%. Figure 4.6 shows the comparison between cumulative oil produced with and without EM heating. Without any heating the cumulative oil produced at the end of 1 year is approximately 7,000 barrels. With EM heating in place, the cumulative oil produced increases to 21,000 barrels for the same time period.

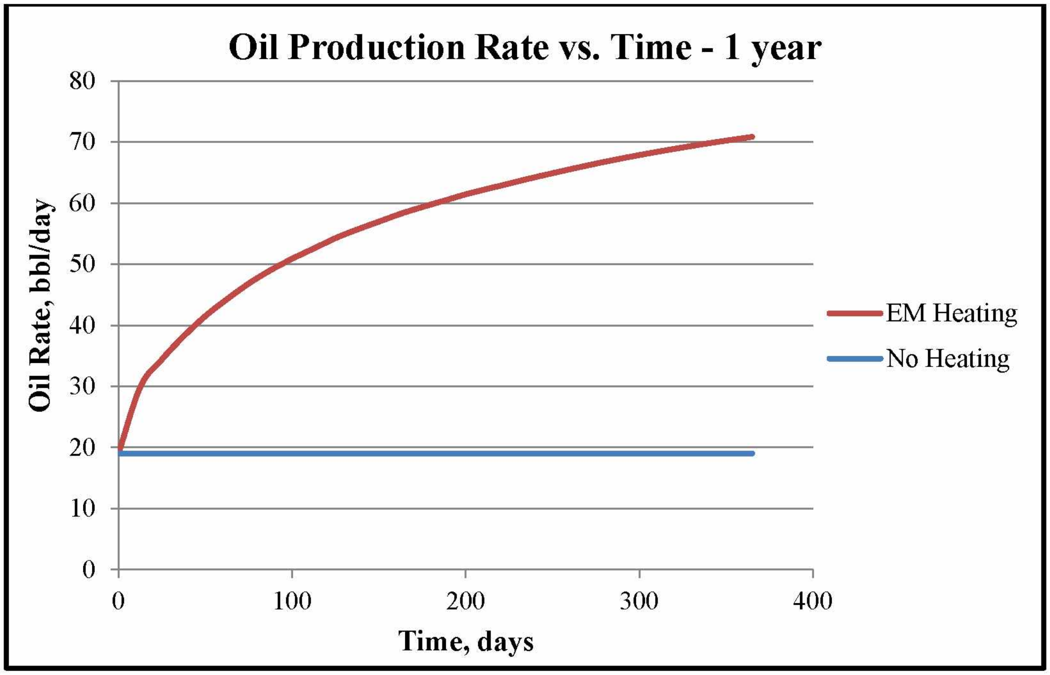

Figure 4.5: Oil Production Rates after 1 Year, with and without EM Heating

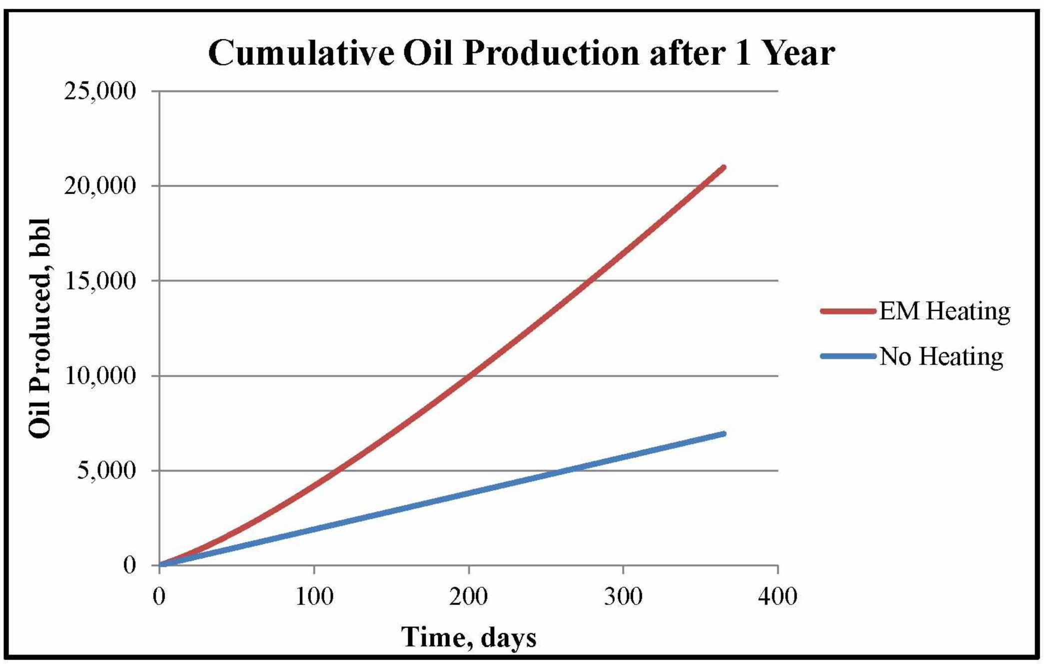

Figure 4.6: Cumulative Oil Produced after 1 Year, with and without EM Heating

The pressure profile after 1 year of production under EM heating is shown in Figure 4.7.

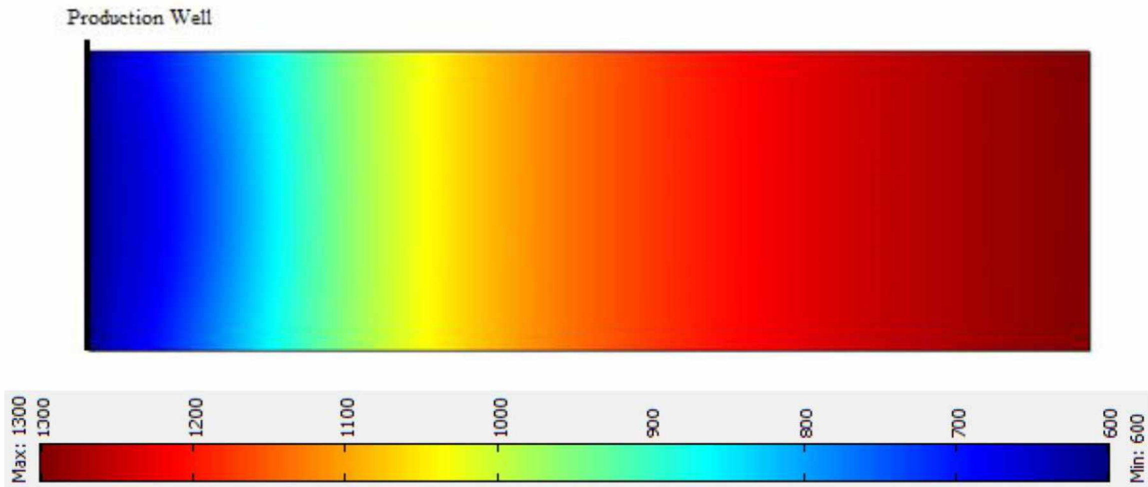

Figure 4.7: Pressure (psi) Profile after 1 Year of Production with EM Heating.

4.2.2 After 3 Years of EM Heating

After 3 years of continuously heating the reservoir by EM waves, the temperature further increases (Figure 4.8). The temperature near the wellbore rises to 239ºF, almost a 100% increase from the initial reservoir temperature and a 13% increase in the temperature since the first year. The temperature at a distance of 33 ft (10 m) increases to 162ºF, a 35% increase from the initial temperature and a 15% increase since the end of first year. Farther away from the wellbore, the temperature at a distance of 65 ft (20 m) increases to

140ºF. This is a 16% increase in the reservoir temperature from the initial temperature.

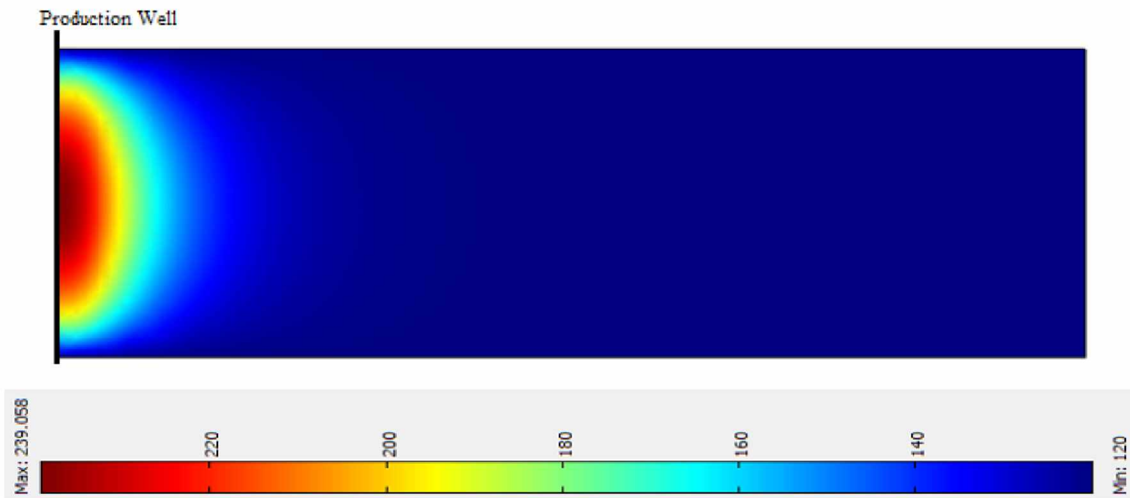

Figure 4.8: Temperature (ºF) Profile after 3 Years of EM Heating

Due to the temperature rise after 3 years of EM heating, the viscosity of the heavy oil further reduces (Figure 4.9). Near the wellbore the viscosity reduces to 44.3 cp (0.0443 Pa*s), a 98.5% reduction from the initial viscosity and a 55% reduction since the first year of heating. Figure 4.10 shows the production rate comparison for no heating and EM heating for 3 years. The oil production rate at the end of 3 years due to continuous heating increases to 84 bbl/day.

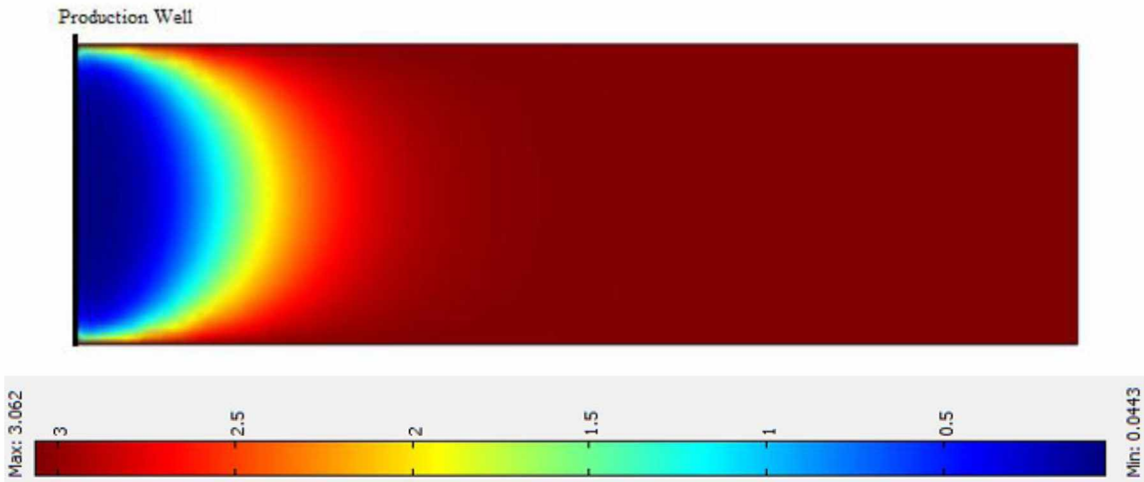

Figure 4.9: Viscosity Profile in Pa*s (1Pa*s = 1000 cp) after 3 Years of EM Heating

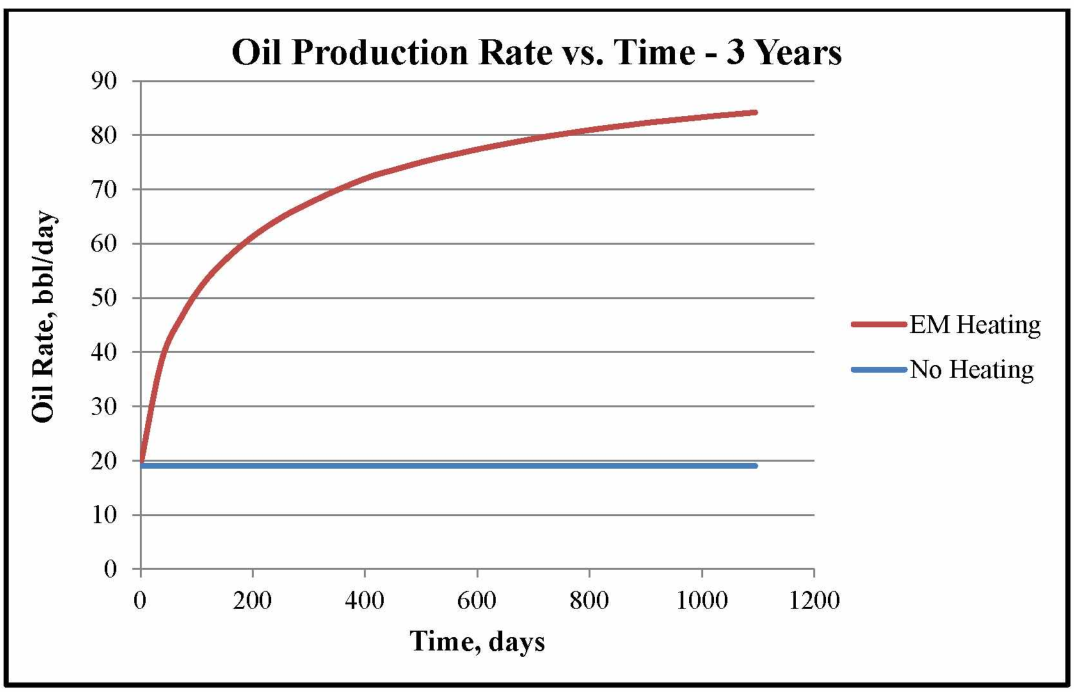

Figure 4.10: Oil Production Rates after 3 Years, with and without EM Heating

Figure 4.11 shows the comparison between the cumulative oil produced for no heating and EM heating for 3 years. After 3 years of EM heating, the cumulative oil produced is approximately 80,000 barrels. With no heating it is 20,800 barrels. Thus EM heating increases cumulative oil produced by 59,200 barrels over a period of three years.

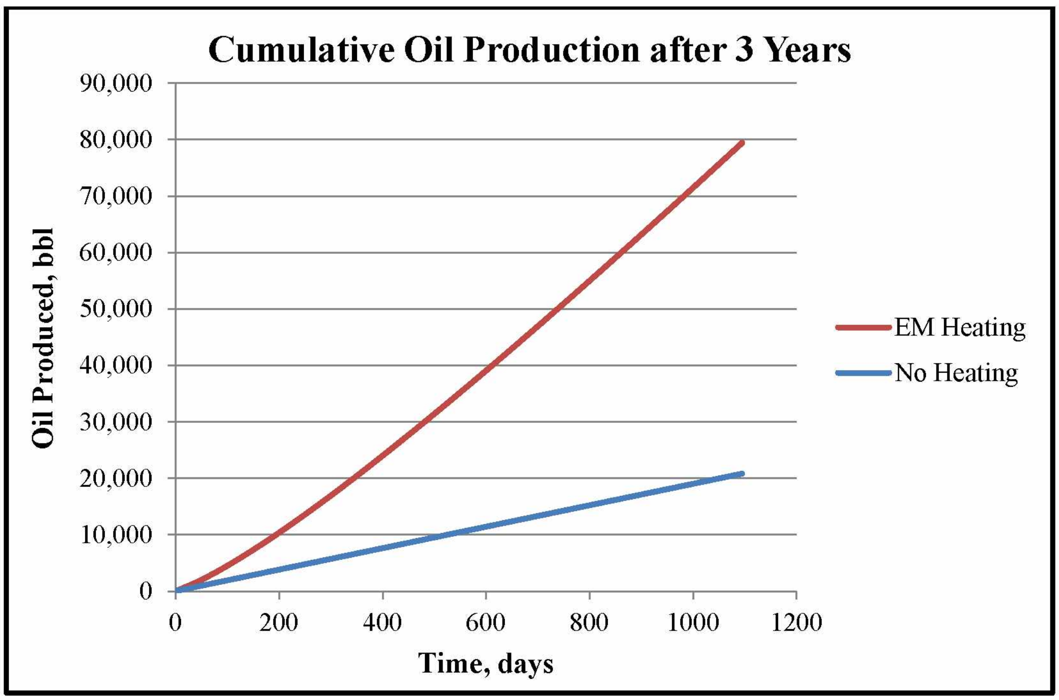

Figure 4.11: Cumulative Oil Produced after 3 Years, with and without EM Heating

Figure 4.12 shows the pressure profile after 3 years of production due to EM heating.

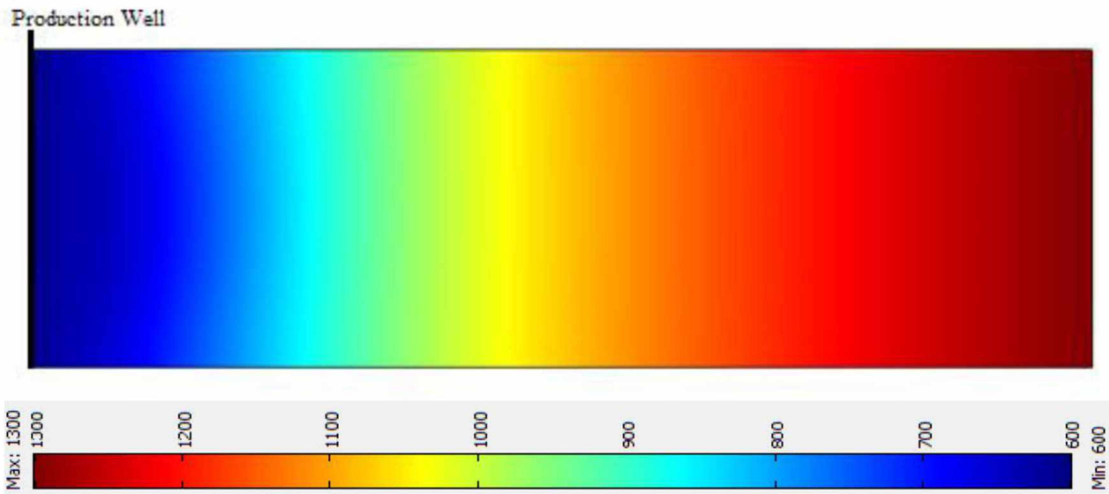

Figure 4.12: Pressure (psi) Profile after 3 Years of Production with EM Heating

4.2.3 Comparison with Work Described in Literature

Carrizales and Lake (2009) studied the effect of EM heating for heavy oil recovery. Instead of using available multi-physics modules in COMSOL to develop their model, they imported their own partial differential equations in COMSOL to model heat and mass transfer phenomenon. The microwave source was converted into a heat source dependent upon the absorption coefficient and the other electrical properties that affect EM wave propagation.

Carrizales and Lake (2009) used an input frequency of 915 MHz and 70 KW input power. The height of the pay zone in their model was 30 meters (100 ft) with the width of the reservoir as 100 meters (330 ft). The reservoir was heated for a period of 3 years. The results of their model showed that after 3 years of EM heating, the temperature near the wellbore rises to 245°F, and at a distance of 20 meters (65 ft) from the wellbore the temperature rises to 142°F (Figure 4.13).

For this research work the built in PDEs in COMSOL were used. The thickness and external radius of the reservoir were kept similar to Carrizales and Lake's (2009) model as 100 ft and 330 ft, respectively. The results of this research work match closely to Carrizales and Lake's (2009) work. Temperature near the wellbore for this work after 3 years of EM heating increased to 240ºF, and at a distance of 20 m (65 ft) from the wellbore, temperature increased to 140ºF (Figure 4.8).

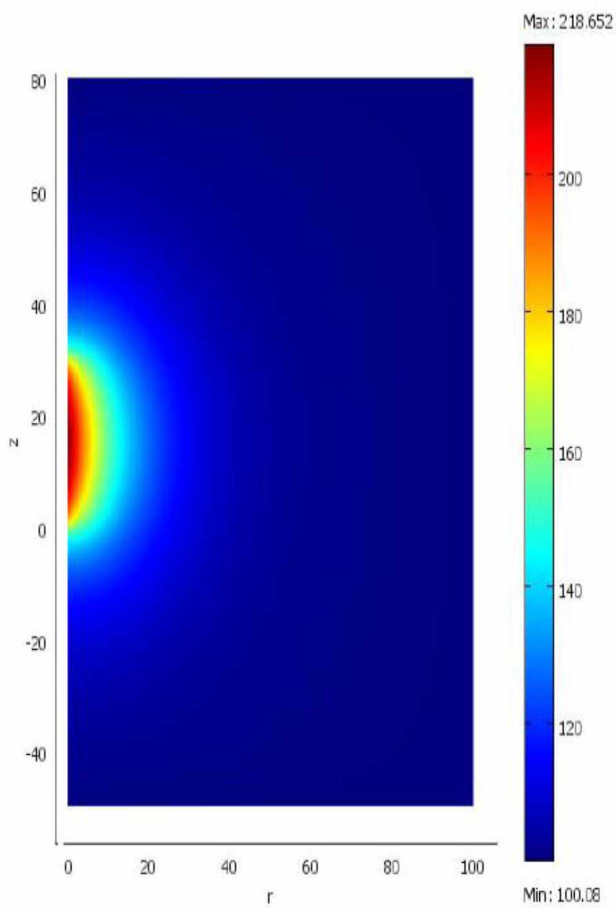

Figure 4.13: Temperature (ºF) Profile after 3 Years of EM Heating with COMSOL (Carrizales and Lake, 2009)

The EM heating model developed in this work using built in PDEs in COMSOL was then applied to the reservoirs on the Alaska North Slope where the temperatures are lower and the oil viscosities higher (discussed in section 4.3.3). The results of EM heating on oil production rate were then compared to results obtained from Cyclic Steam Stimulation methods (Chapter 5).

4.3 Factors Affecting EM Heating

4.3.1 Frequency

The increase in temperature around the wellbore was studied for different frequencies ranging from 140 MHz to 2450 MHz for an input power of 70 KW (Figure 4.14).

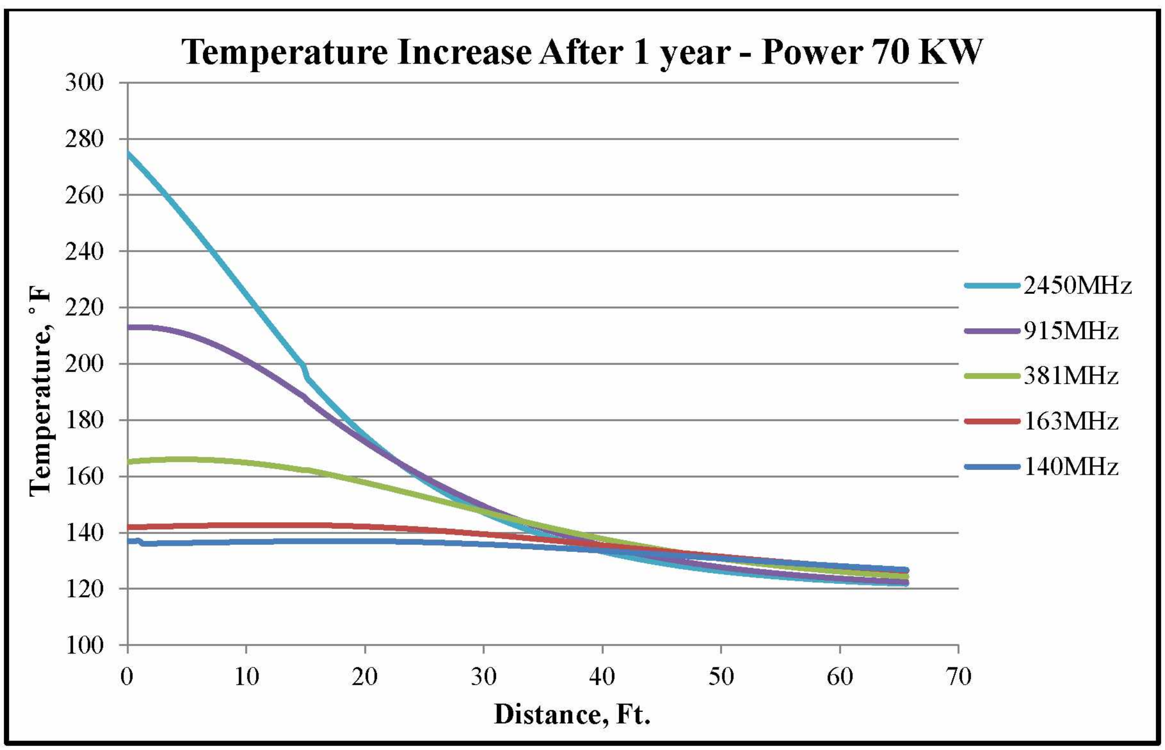

Figure 4.14: Temperature Increase after 1 Year of EM Heating-Power 70 KW.

Figure 4.14 shows that the higher the frequency, the higher is the rise in temperature, but the depth of penetration reduces as the frequency increases. Figure 4.15 shows the percentage increase in temperature at a distance of 65 ft from the EM heat source for different frequencies and a constant power of 70 KW after 1 year.

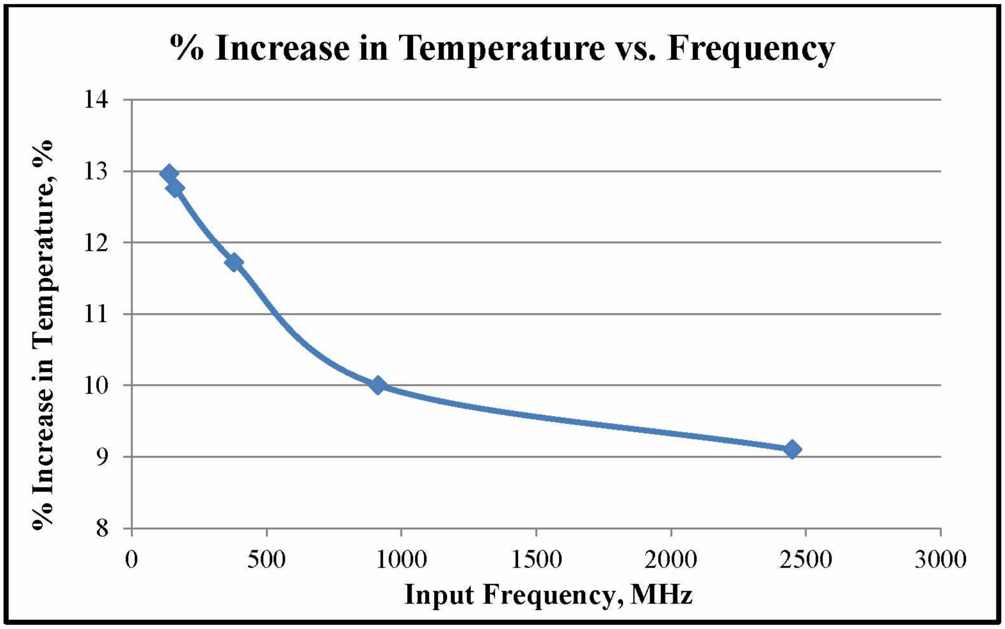

Figure 4.15: % Increase in Temperature at a distance of 65 ft from the EM source after 1 year of EM Heating. Power 70 KW

In previous chapters it has been stated that dipoles in a polar molecule try to align themselves in a changing electric field. This movement generates internal friction that is converted into heat. As the frequency increases, the dipoles rotate faster in order to align with the alternating field. This increased speed of rotation generates heat at an increased rate and as the frequency increases, there is much higher increase in temperature near the wellbore.

With the increase in frequency, the value of the absorption coefficient increases from 0.0364 m^{-1} for 140 MHz to 0.2604 m^{-1} for 2450 MHz (Table 2.1). The value of the absorption coefficient changes, because the absorption coefficient is a function of relative permittivity (ε) and electrical conductivity (σ), and these two parameters change with changing frequency. This increase means that the attenuation of EM waves per meter is more as the frequency increases. Hence the penetration depth becomes less with increasing frequency.

Figure 4.16 shows the cumulative oil produced for a constant power of 70 KW and change of frequency from 140 MHz to 2450 MHz over a heating period of 5 years. The results show that as the frequency increases, the cumulative oil produced increases. This is because of the higher heating rate at higher frequencies, and thus a much higher temperature increase near the wellbore. The results also show that as the frequency is increased from 915 MHz to 2450 MHz, there is only an increment of ~8000 bbl in oil produced over a period of 5 years (Figure 4.17). Increasing the frequency above 915 MHz to 2450 MHz, the increase in oil production seems to flatten out. This can be attributed to the fact that heating at 2450 MHz reduces the depth of penetration of EM waves due to higher values of absorption coefficient and greater attenuation in the waves. It can be concluded that 70 KW and 915 MHz would be an optimum power and frequency combination to be used in a case of EM heating for an initial reservoir temperature of 120°F and for the given reservoir properties.

The optimum combination of power and frequency will be different for different reservoirs and will depend upon electrical properties as well as reservoir rock and fluid properties. Based on the given reservoir properties and conditions, a sensitivity analysis must be conducted and, depending on the increase in oil production, optimum values of power and frequency must be decided.

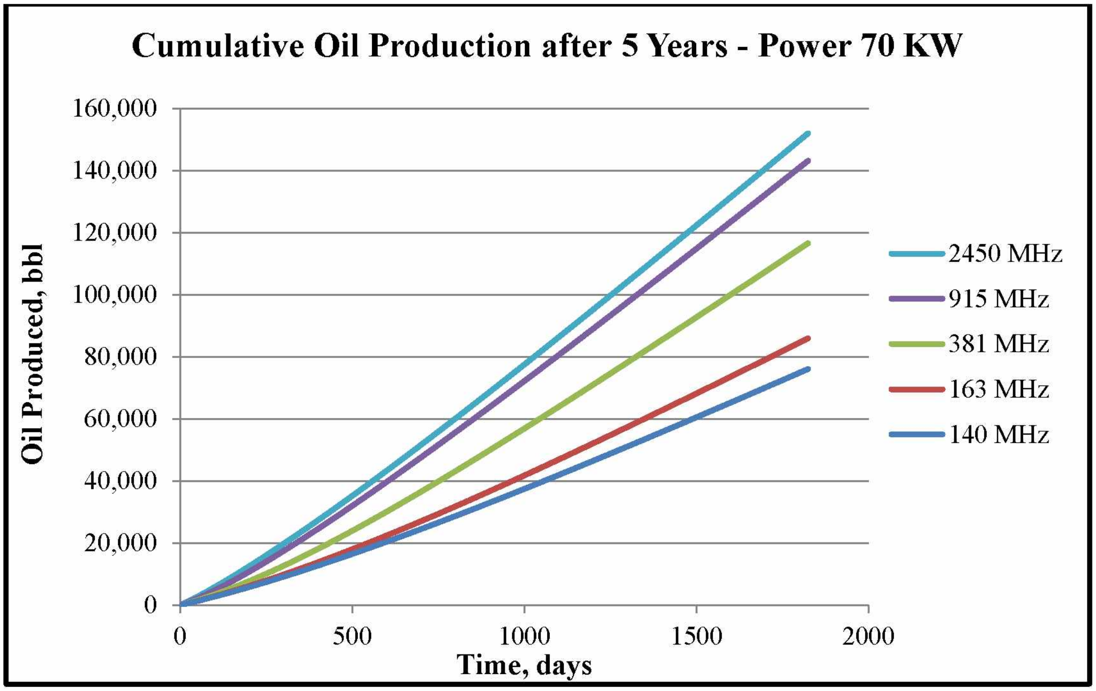

Figure 4.16: Cumulative Oil Produced after 5 Years of EM Heating-Power 70 KW.

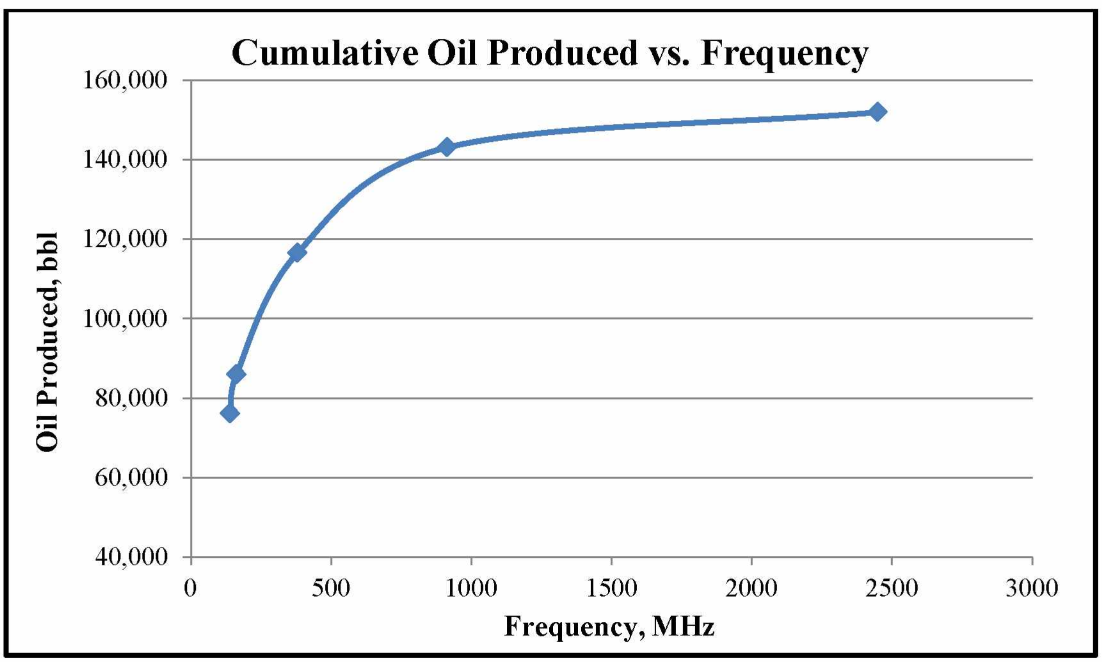

Figure 4.17: Cumulative Oil Production vs. Frequency for a Period of 5 Years

4.3.2 Power

Temperature increase in the reservoir was studied for various power levels ranging from 10 KW to 100 KW for two different frequencies: 915 MHz and 2450 MHz.

Figure 4.18 shows the temperature distribution for an input frequency of 915 MHz with different combinations of input power. Since EM heating is directly proportional to the input power, as the power increases there is much higher increase in temperature. With higher increase in temperature, there is increase in the cumulative oil produced as well, which is shown in Figure 4.19 for an input frequency of 915 MHz.

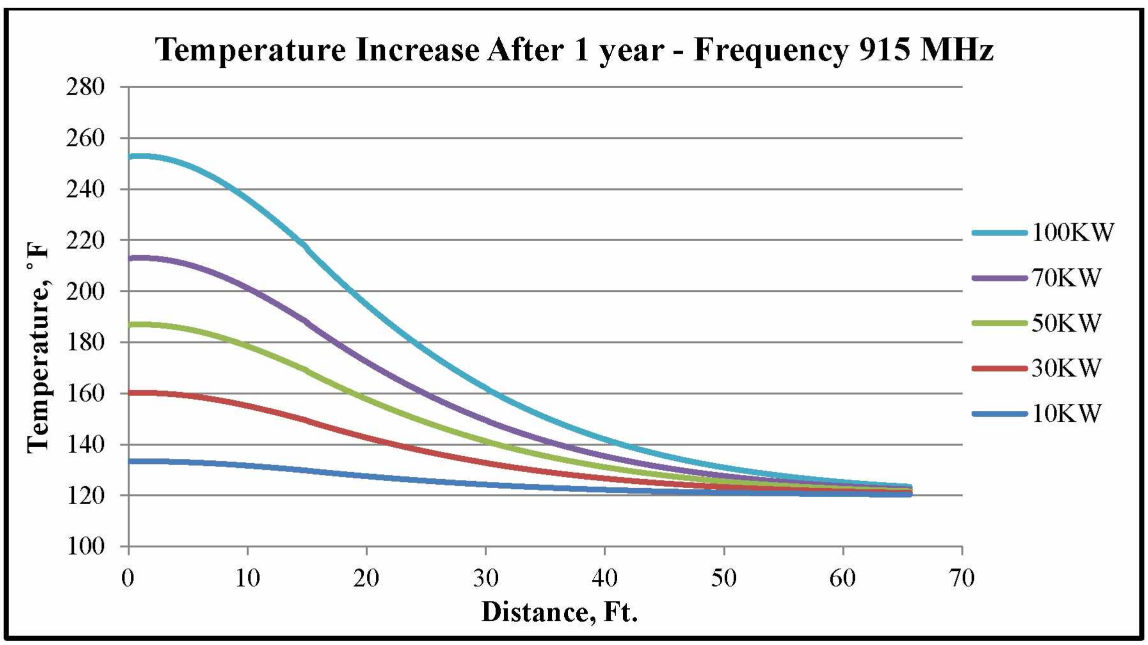

Figure 4.18: Temperature Increase after 1 Year of EM Heating-Frequency 915 MHz.

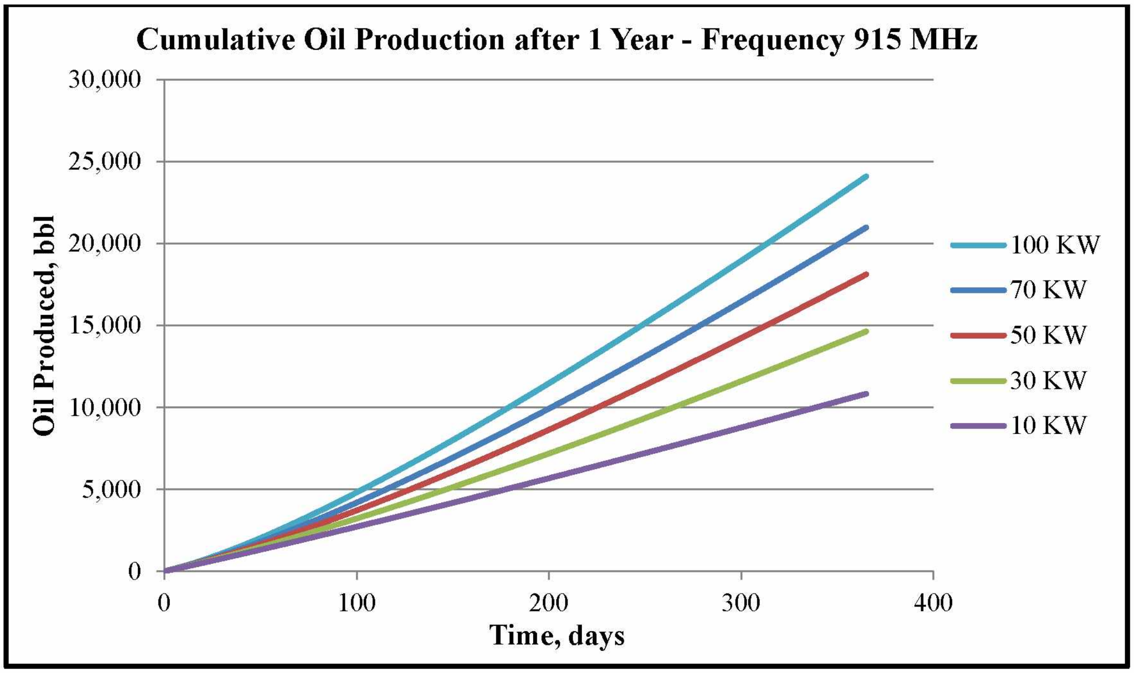

Figure 4.19: Cumulative Oil Produced after 1 Year of EM Heating-Frequency 915 MHz.

Figure 4.20 shows the temperature increase for different power levels for a frequency of 2450 MHz after 1 year of EM heating.

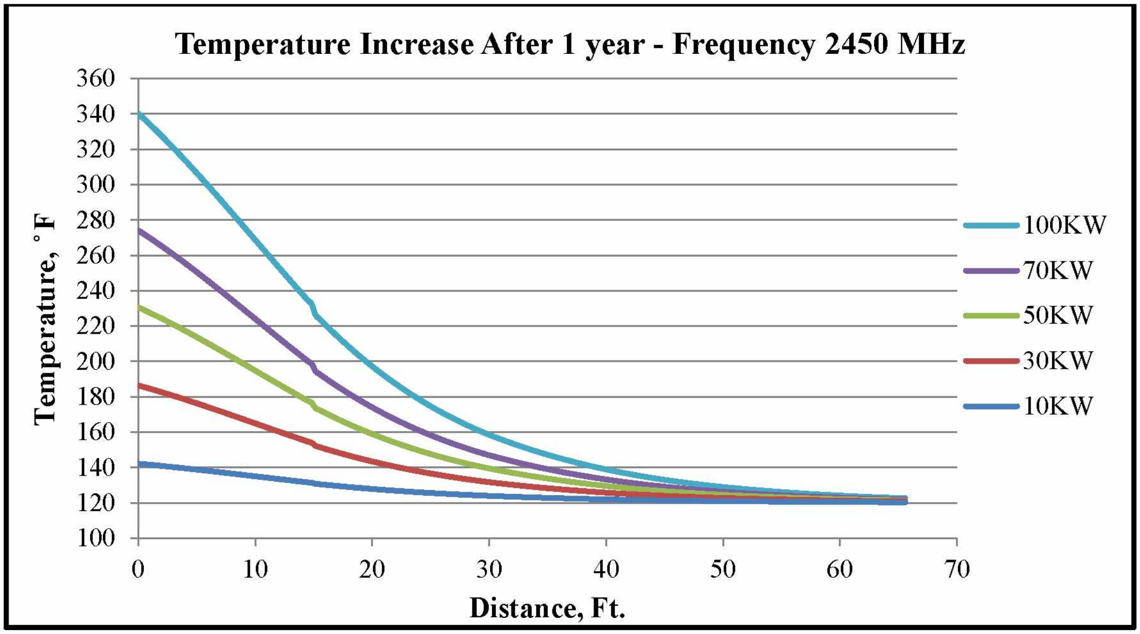

Figure 4.20: Temperature Increase after 1 Year of EM Heating-Frequency 2450 MHz.

Since 2450 MHz is a much higher frequency level in the microwave region than 915 MHz, the depth of heating is reduced due to higher value of absorption coefficient. For example, for 100 KW input power and 915 MHz frequency, the temperature at a distance of 30 ft after 1 year of EM heating is 162°F (Figure 4.18), whereas for 100 KW and 2450 MHz for the same time period the temperature at 30 ft is ~153°F (Figure 4.20). But since the temperature near the wellbore is higher, much higher oil production is witnessed (Figure 4.21).

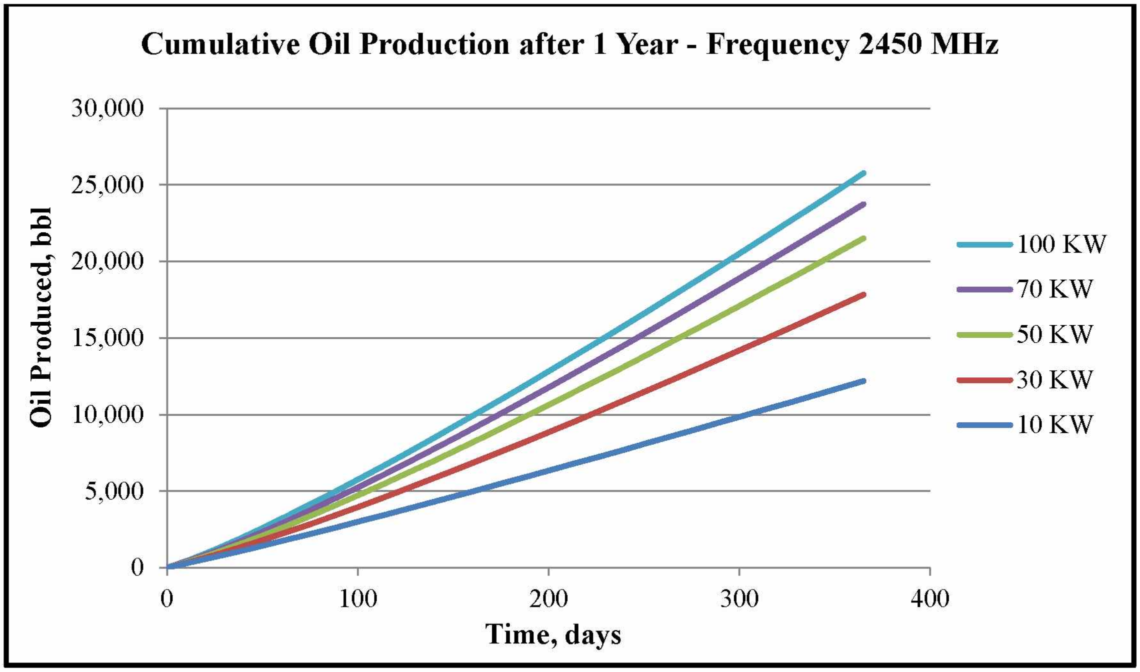

Figure 4.21: Cumulative Oil Produced after 1 Year of EM Heating-Frequency 2450 MHz.

4.3.3 Reservoir Temperature

The Ugnu reservoir on the Alaska North Slope is a very shallow formation at depths ranging from 1500 to 4000 ft. (Werner, 1984; Olsen et al., 1992). Due to close proximity to a 2000 ft thick layer of permafrost, temperatures in these types of reservoirs are fairly low, anywhere from 45–100°F (Olsen et al., 1992). The oil viscosity at these temperatures is greater than 10,000 cp.

4.3.3.1 Initial Reservoir Temperature of 80°F

To study the heating of low temperature reservoirs, the initial reservoir temperature used in the model was set at 80°F. The oil viscosity at 80°F was approximately 19,300 cp. EM heating was applied for a period of 3 years and its effect on the viscosity and oil production was analyzed.

After 3 years of EM heating at 915 MHz frequency and 70 KW input power, the temperature near the wellbore rises to 200°F. At a distance of 33 ft from the wellbore it rises to 123ºF (Figure 4.22). The initial oil viscosity at 80ºF is 19,332 cp (19.332 Pa*s), which is reduced to 152 cp (0.152 Pa*s) after 3 years of EM heating (Figure 4.23).

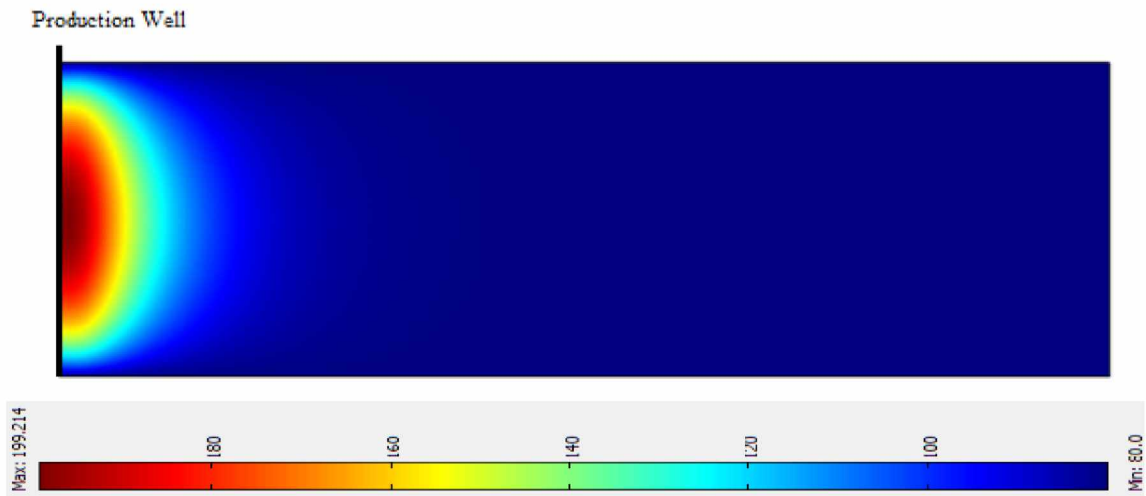

Figure 4.22: Temperature (ºF) Profile after 3 Years of EM Heating

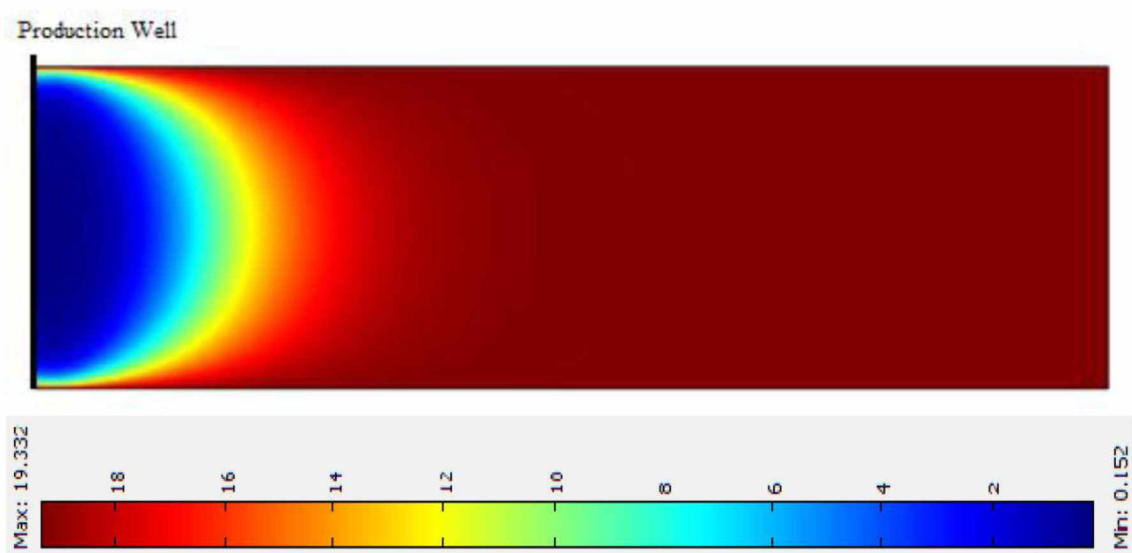

Figure 4.23: Viscosity Profile in Pa*s (1Pa*s = 1000 cp) after 3 Years of EM Heating

For a reservoir with an initial temperature of 80ºF and an initial oil viscosity of 19,300 cp, after 3 years of EM heating the oil production rate increases from 4 bbl/day to 14 bbl/day (Figure 4.24).

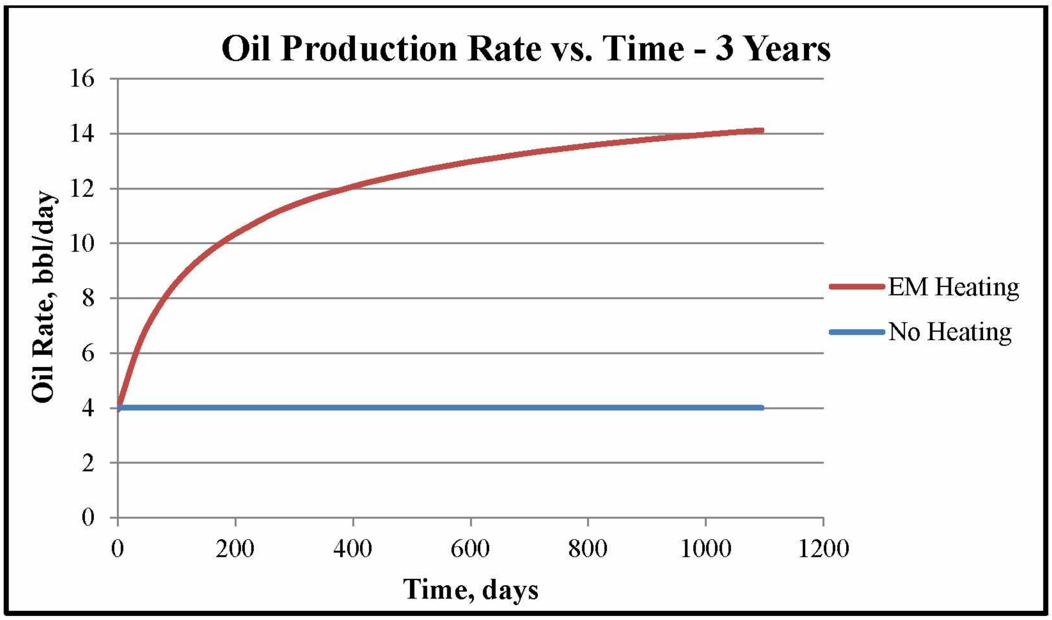

Figure 4.24: Oil Production Rate after 3 Years-Initial Reservoir Temperature 80ºF.

The cumulative oil produced after 3 years of EM heating is 13,300 bbl, whereas the oil produced without any heating after 3 years is 4,300 bbl (Figure 4.25).

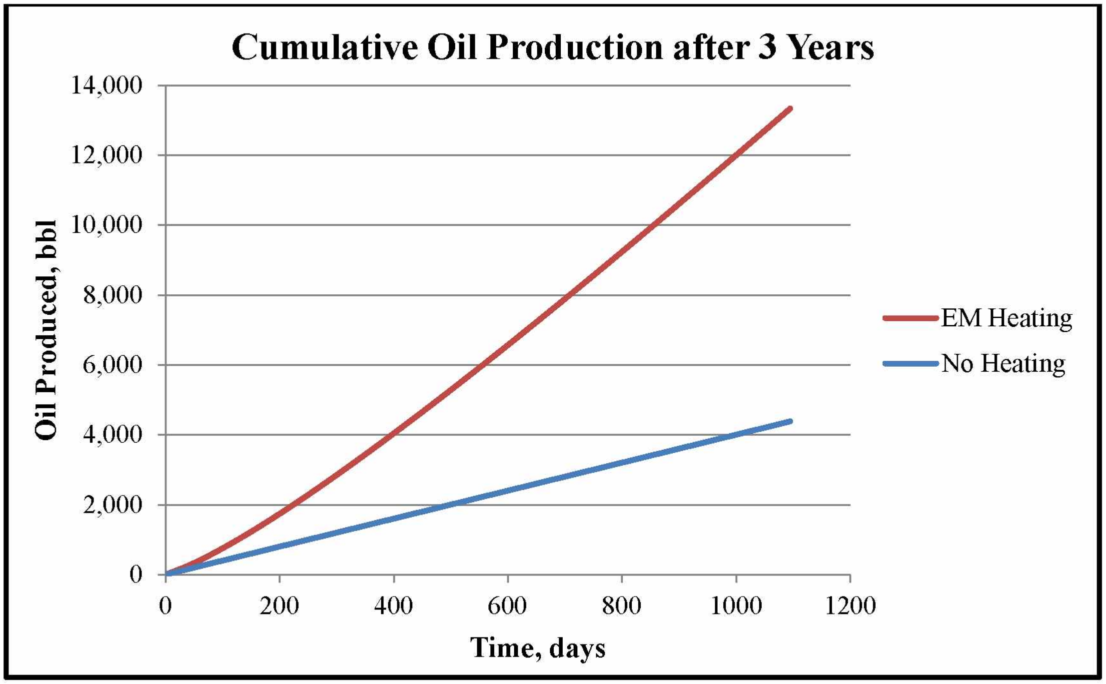

Figure 4.25: Cumulative Oil Produced after 3 Years-Initial Reservoir Temperature 80°F.

4.3.3.2 Initial Reservoir Temperature of 45°F

To mimic the low reservoir temperatures of the Ugnu reservoir, the initial temperature was set at 45°F with an initial oil viscosity of approximately 123,000 cp. The reservoir was heated for a period of 3 years with an input power of 70 KW at a frequency of 915 MHz, and the effect on viscosity and production was analyzed.

After 3 years of heating, the temperature near the wellbore rises to 168°F. At a distance of 33 ft, it increases to 100°F (Figure 4.26).

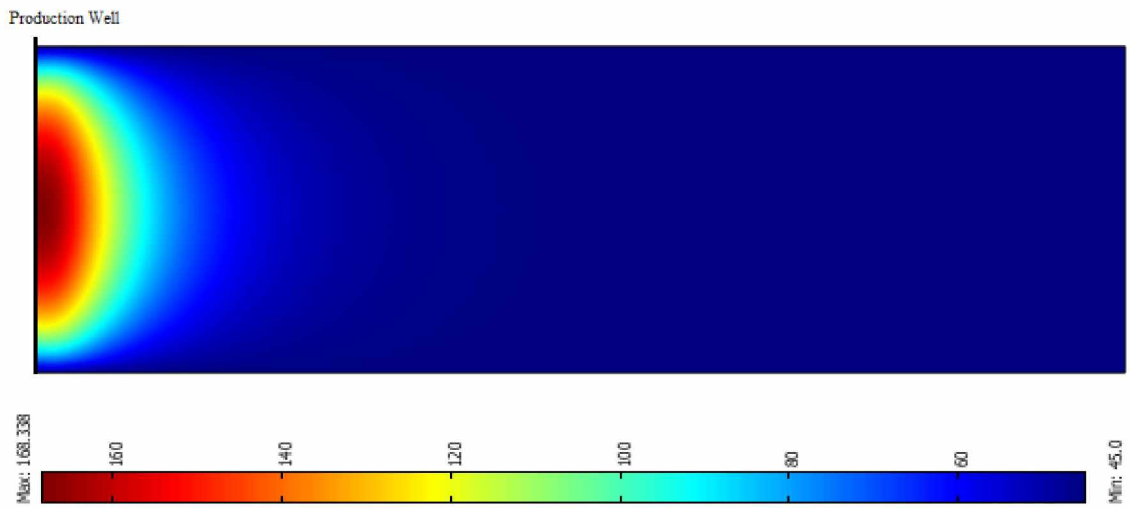

Figure 4.26: Temperature (^oF) Profile after 3 Years of EM Heating

After 3 years of EM heating the viscosity reduces from an initial value of 123,181 cp (123.181 Pa*s) to 452 cp (0.452 Pa*s) near the wellbore (Figure 4.27).

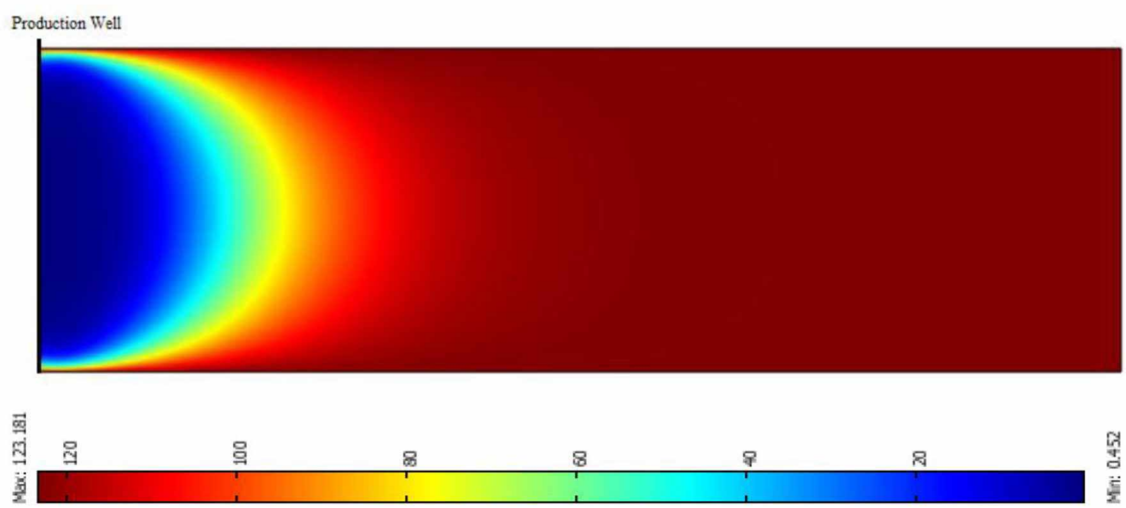

Figure 4.27: Viscosity Profile in Pa*s (1Pa*s = 1000 cp) after 3 Years of EM Heating

Since this reduction in viscosity is not significant enough to aid any oil production, power input was increased to 100 KW and the frequency was kept constant at 915 MHz. Heating was continued for a period of 5 years. After 5 years, the reservoir temperature near the wellbore rises to 220ºF. At a distance of 33 ft from the wellbore, the temperature increases to 120ºF (Figure 4.28).

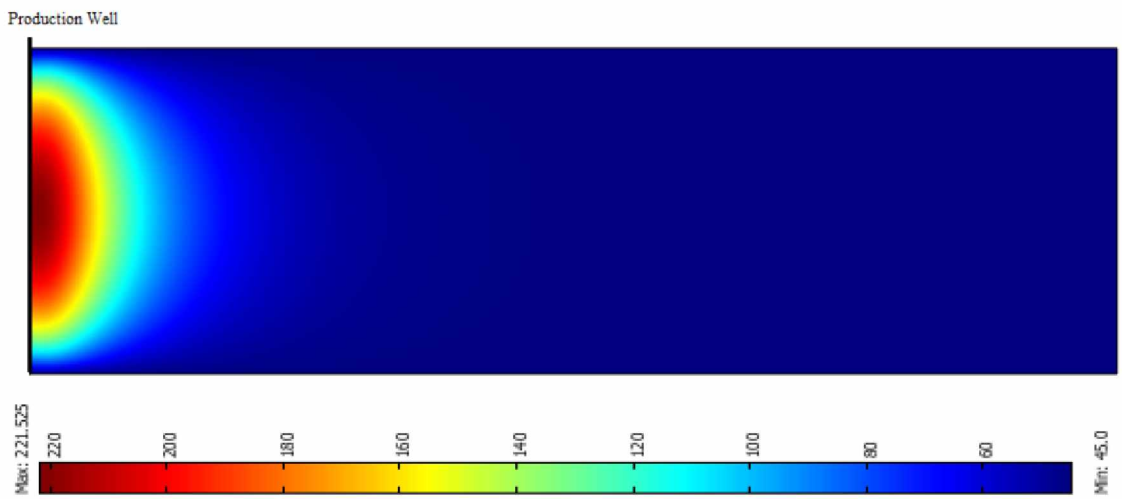

Figure 4.28: Temperature (ºF) Profile after 5 Years of EM Heating

The viscosity of the oil near the wellbore reduces to 75 cp after 5 years of EM heating. At a distance of 33 ft from the wellbore, it reduces to 3000 cp from an initial value of 123,000 cp, a considerable reduction in viscosity (Figure 4.29).

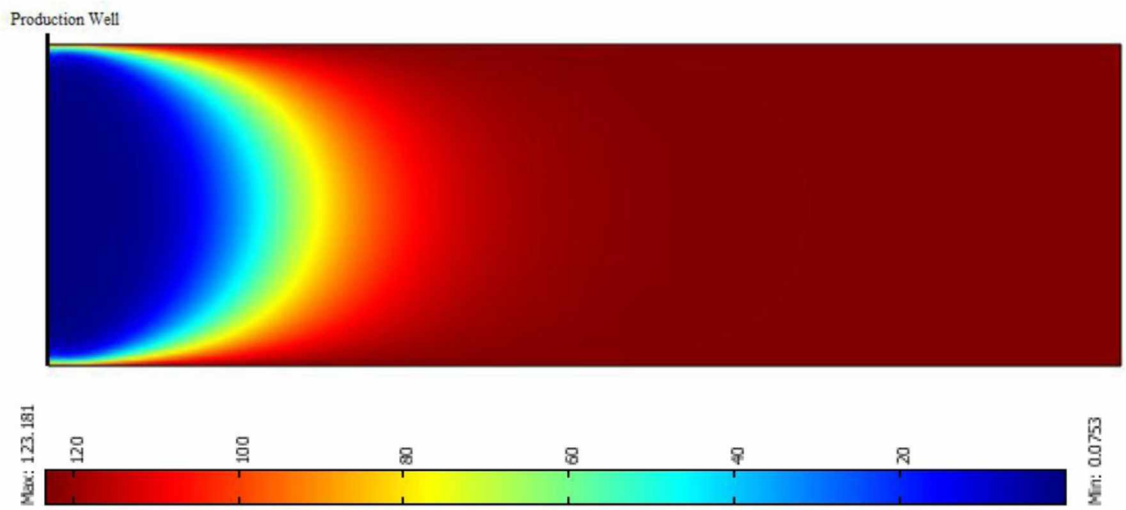

Figure 4.29: Viscosity Profile in Pa*s (1Pa*s = 1000 cp) after 5 Years of EM Heating

The production from the reservoir increases to ~6 bbl/day after the heating period ends (Figure 4.30).

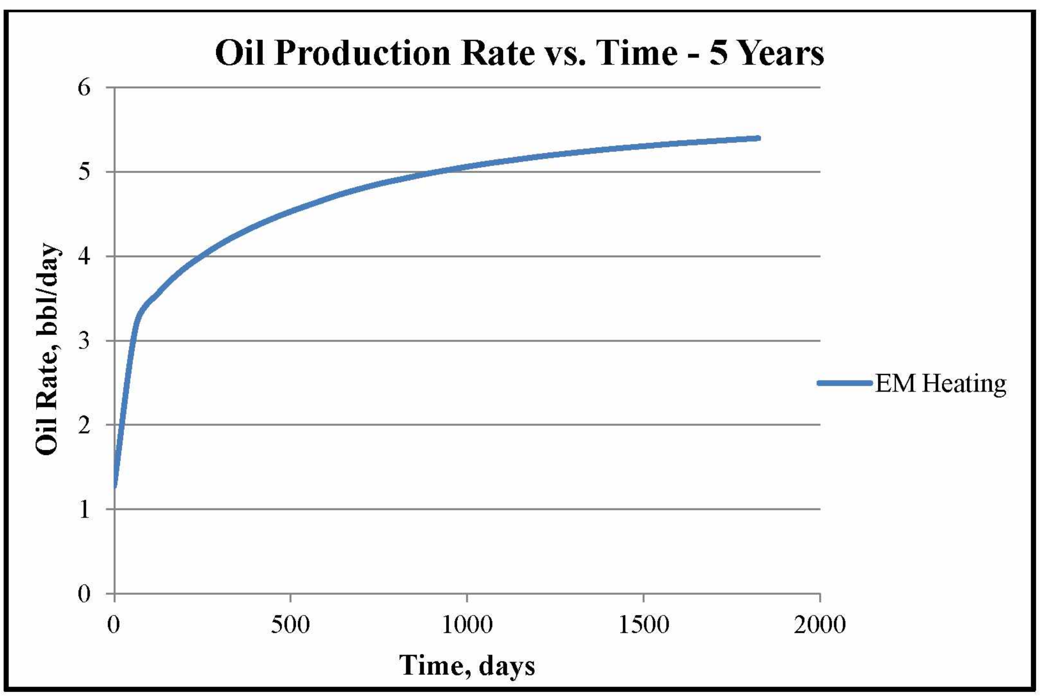

Figure 4.30: Oil Production Rate after 5 Years-Initial Reservoir Temperature 45ºF.

The production profile shows a sudden increase of production to 3.5 bbl/day at around 60 days. This may be because the oil, which was initially too viscous to flow, becomes sufficiently mobile due to heating. Later the flow increase becomes more gradual, but continues as heating continues. After 5 years the cumulative oil produced is ~9,000 bbl (Figure 4.31).

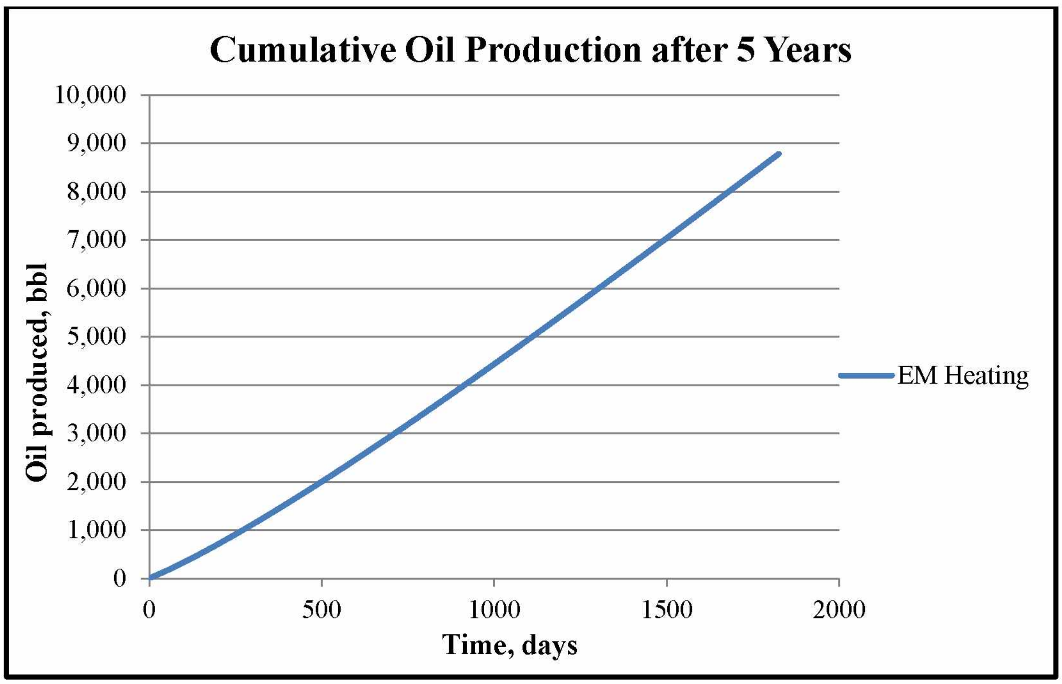

Figure 4.31: Cumulative Oil Produced after 5 Years-Initial Reservoir Temperature 45ºF.

As shown in Figure 4.28, the heat penetrates about 30 ft deep, where the oil viscosity reduces to 3000 cp. This reduction in near-wellbore viscosity is significant when compared to initial viscosity at initial reservoir temperature of 45ºF. But this reduction is not substantial enough to aid any significant oil production. Oil farther away from the wellbore is still at a very high viscosity.

The results suggests that as we move from viscous oil (3000 cp at initial reservoir temperature of 120ºF) to very viscous oil (123,000 cp at initial reservoir temperature of 45ºF), more and more energy is needed to increase the reservoir temperature to significant values as the initial reservoir temperature is low. Oil mobility is negligible at reservoir conditions, and the driving force, in this case the reservoir pressure is not sufficient to assist in production.

5. COMPARISON OF EM HEATING TO CYCLIC STEAM STIMULATION

5.1 Cyclic Steam Stimulation

Cyclic steam stimulation (CSS) is the most commonly used thermal method for the recovery of heavy oil (Green and Willhite, 1998; Islam and Chilingarian, 1995). In this method, steam is injected for a brief period of time after which the well is shut-in for a soaking period, where the heat reduces the viscosity of the heavy oil. After the soaking period, the well is opened for production. The heated oil, now at lower viscosity, is produced along with the water (Green and Willhite, 1998; Carrizales, 2010). Figure 5.1 shows the mechanism of CSS. This method is also commonly referred to as huff & puff process.

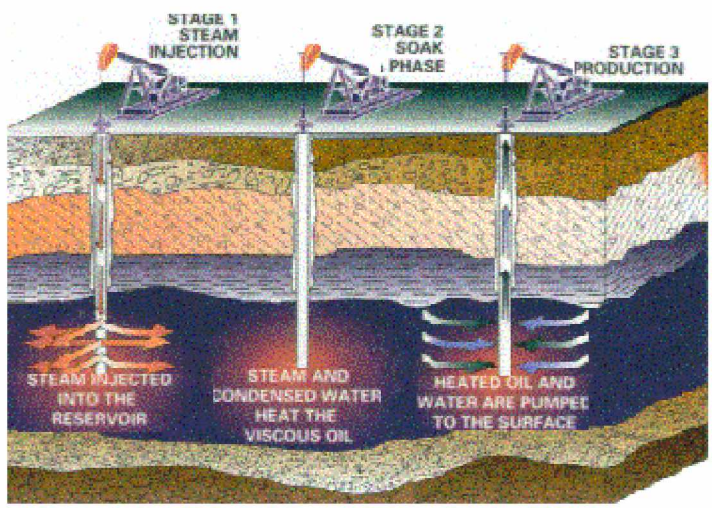

Figure 5.1: Cyclic Steam Stimulation Process

(Virtual Science Fair, http://www.odec.ca/projects/2003/wongi3i/public_html/tech.html)

5.2 CSS Model Using CMG-STARS

To compare the results of EM heating with CSS, a 50*50*10 Cartesian grid model was built using CMG-STARS (Figure 5.2). The dimension of the grid block in I and J directions was kept at 20 ft. In the K direction the dimension of the grid block was 10 ft. There was one injection/production well at the center of the reservoir.

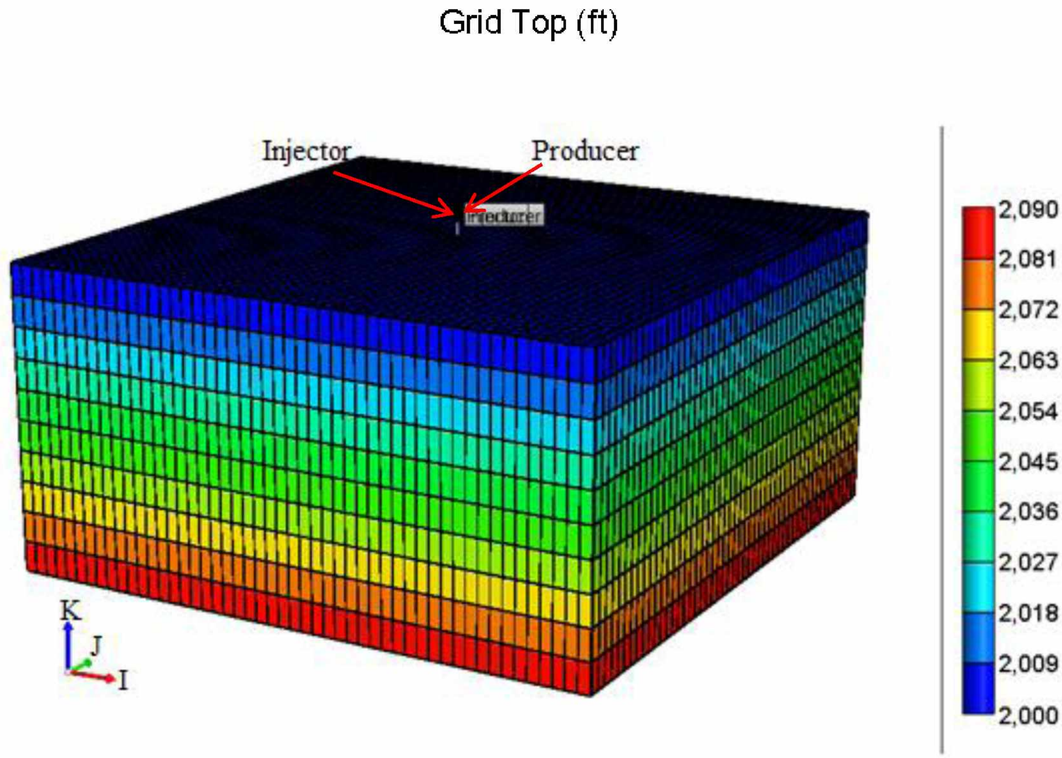

Figure 5.2: CSS Cartesian Grid Model in CMG-STARS

5.3 Initial Reservoir Temperature of 120°F

To compare the results of EM heating with CSS for a reservoir with an initial temperature at 120ºF, the assumption was made that the total amount of energy injected is the same in both cases (i.e. 6,276 MMBTUS). The steam injection rate with CSS was 260 bbl/day, and the quality of the steam reaching downhole was assumed to be 0.7, taking into consideration heat losses through the tubing. Steam was injected for a period of 10 days after which the well was shut in for a soaking period of 8 days. Thereafter, the well was opened for production for a period of 140 days.

5.4 Results and Discussion

5.4.1 After 1 Year of CSS

After 1 year of steam injection and soaking, the temperature at the injection well increases to 570°F from the initial temperature of 120°F. At a distance of 30 ft from the wellbore the temperature increases to 240°F. The temperature is 145°F another 50 ft from the wellbore (Figure 5.3).

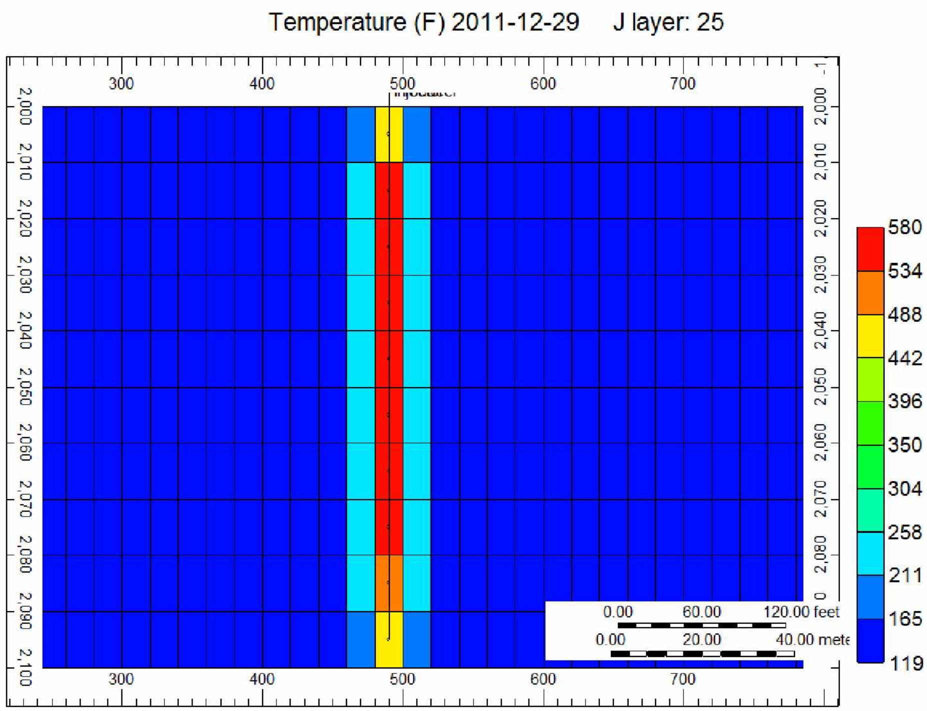

Figure 5.3: Temperature Profile after 1 Year of CSS - Initial Temperature 120°F

The oil viscosity correlation is the same one used for the EM heating model in COMSOL presented by Equation 2.4 with values of D and F as 4.89E-11 Pa*s and 8006 K, respectively. With this correlation the viscosity near the wellbore reduces to 0.0573 cp from an initial viscosity of 3000 cp, and at a distance of 30 ft from the wellbore the viscosity is 45.7 cp (Figure 5.4). This severe reduction in viscosity with temperature is based on the correlation presented and the values of the empirical constants D and F chosen for this study.

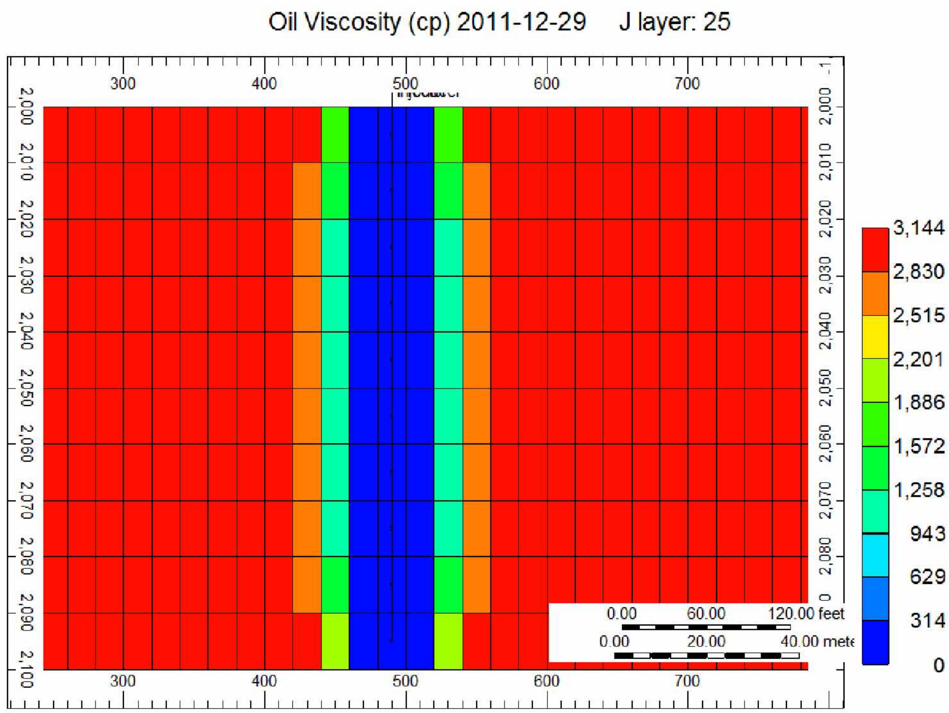

Figure 5.4: Viscosity Profile after 1 Year of CSS - Initial Temperature 120ºF

Figure 5.5 shows the changes in viscosity as a function of temperature used for this work. The viscosity on y-axis is the kinematic viscosity (centistokes) and temperature on x-axis is in ºC.

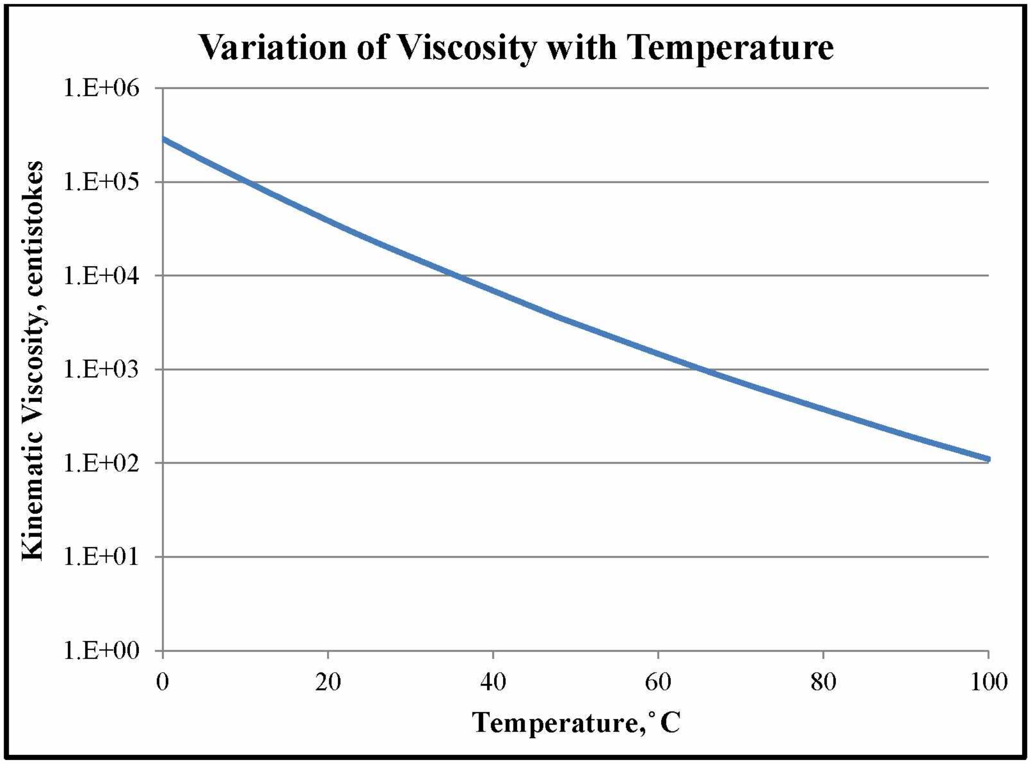

Figure 5.5: Variation of Viscosity with Temperature Used for this Work

Figure 5.6 shows the variation of viscosity with temperature for some actual heavy oil samples (Tissot and Welte, 1984).

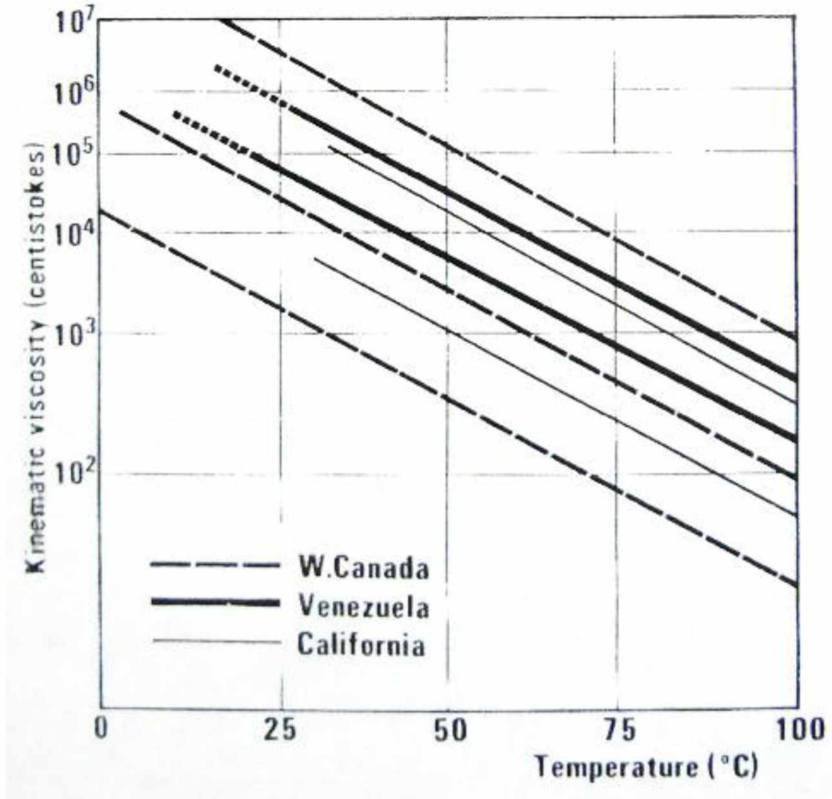

Figure 5.6: Variation of Heavy Oil Viscosity with Temperature

(Tissot and Welte, 1984)

A comparison of Figures 5.5 and 5.6 shows, that such drastic reduction in viscosity of heavy oil with temperature is realistic.

5.4.2 After 3 Years of CSS

After 3 years of steam injection and soaking, the temperature at the injection well increases to 580°F from the initial temperature of 120°F. At a distance of 30 ft from the wellbore, the temperature increases to 283°F, and 50 ft farther from the wellbore the temperature is 175°F (Figure 5.7).

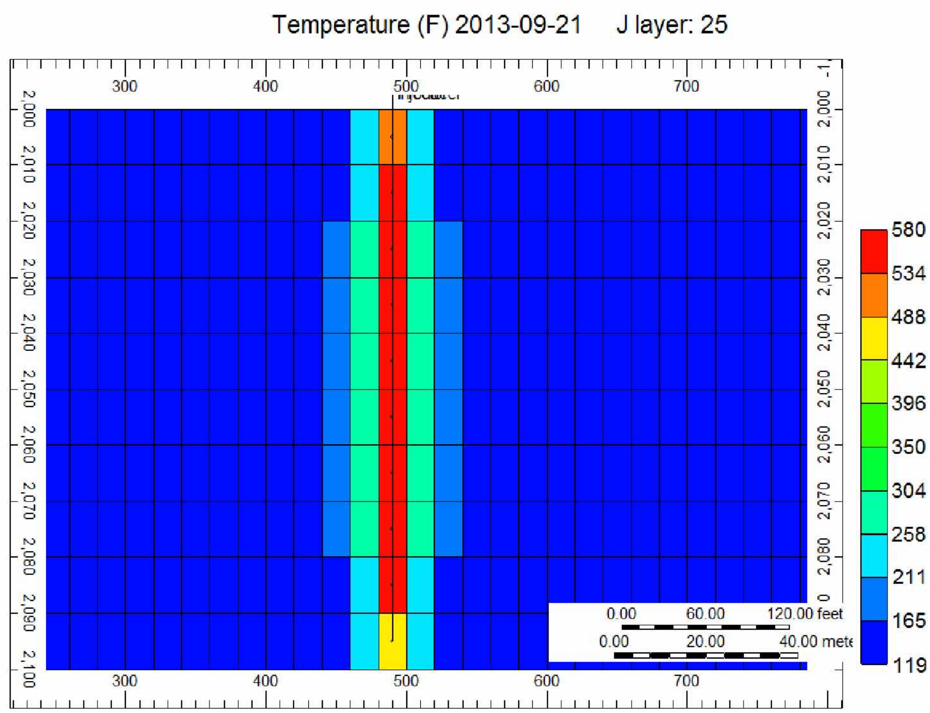

Figure 5.7: Temperature Profile after 3 Years of CSS - Initial Temperature 120°F

Oil viscosity near the wellbore reduces to 0.0522 cp from an initial viscosity of 3000 cp, and at a distance of 30 ft from the wellbore the viscosity is 12 cp. At a distance of 50 ft from the well, the viscosity reduces to ~350 cp (Figure 5.8).

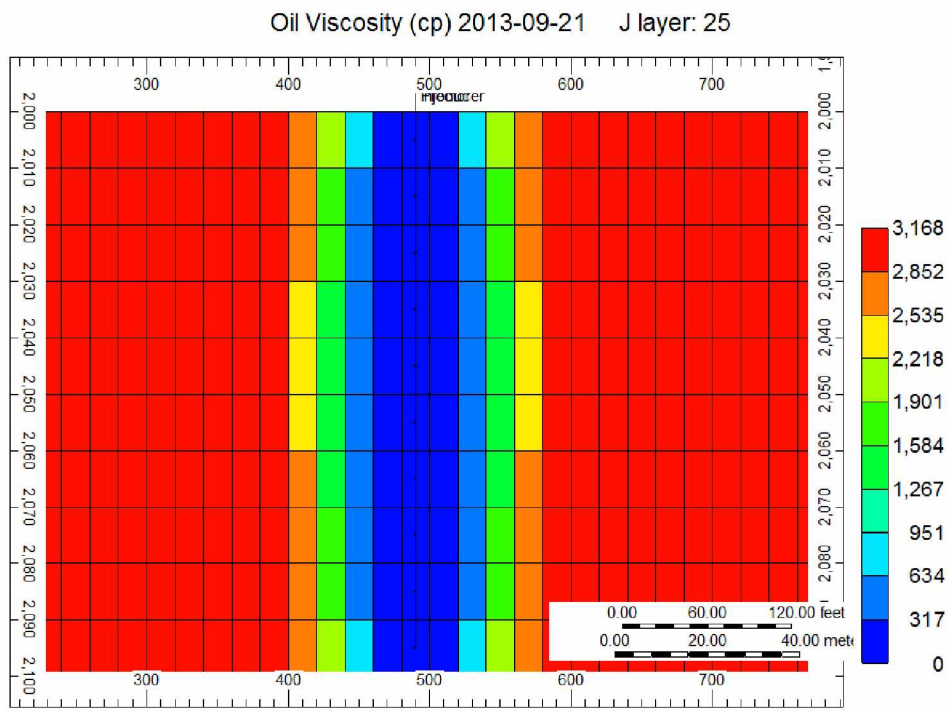

Figure 5.8: Viscosity Profile after 3 Years of CSS - Initial Temperature 120ºF

Figure 5.9 shows the comparison between oil production rate with EM heating and with CSS process. The peaks in oil production rate that are witnessed due to CSS can be attributed to the reservoir simulator artifacts. Figure 5.10 shows the comparison between cumulative oil produced by the two thermal methods. The results show that for the same energy input, EM heating can be used to produce more oil from heavy oil reservoirs. In this case over a period of 3 years, due to EM heating ~80,000 barrels of oil was produced, and for CSS ~37,000 barrels was produced. The EM heating process seems more effective.

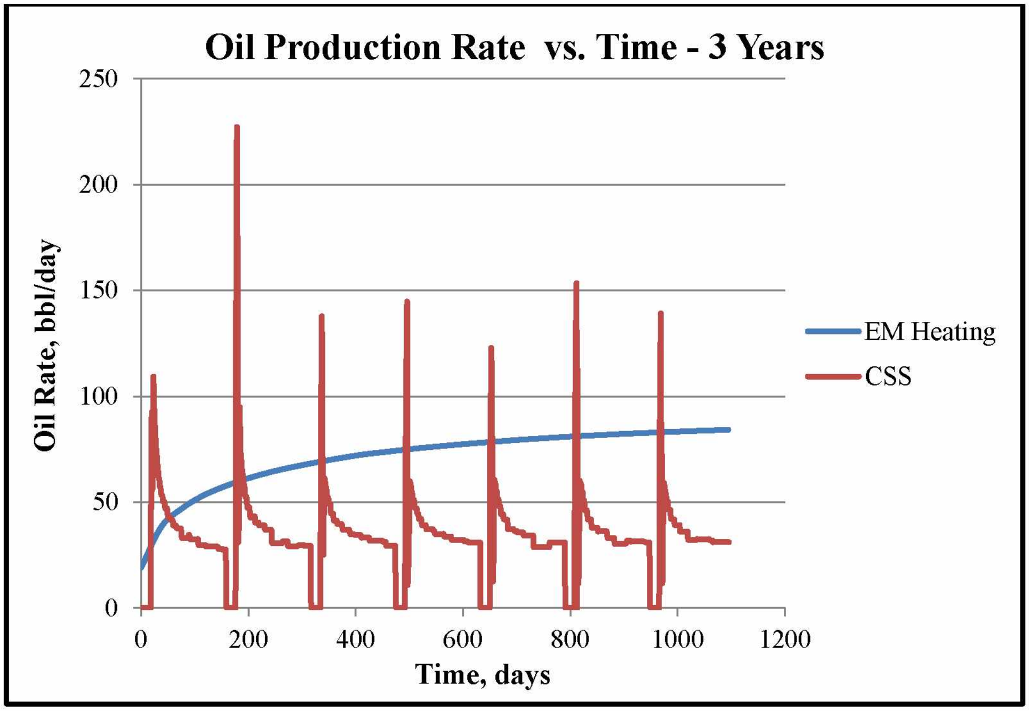

Figure 5.9: Oil Production Rate after 3 Years of EM Heating and CSS

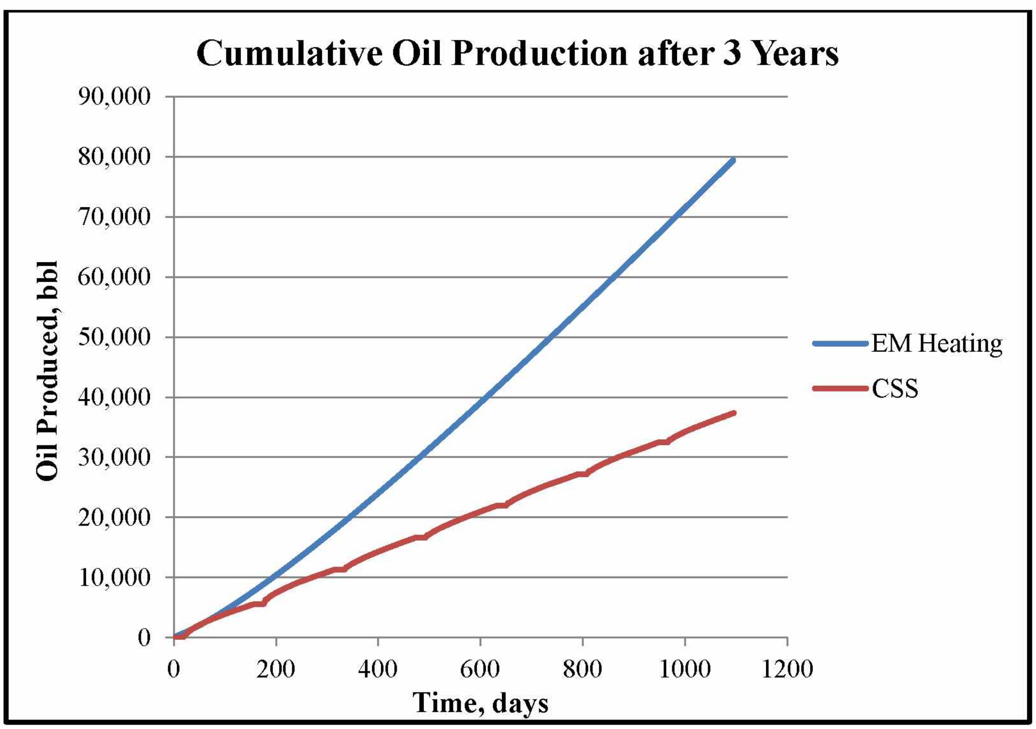

Figure 5.10: Cumulative Oil Production after 3 Years of EM Heating and CSS

Three possible reasons why EM heating proves more effective than CSS in producing oil are:

1. EM heating is essentially a continuous process. It does not require shutting in the well. With CSS, over a period of 3 years (1095 days) the well was shut in for 70 days (10 days of injection period, 7 injection cycles) when steam injection was carried out and for an additional 56 days for soaking (8 days each, 7 cycles). There was a loss in production for a period of 126 days.
2. Since the reservoir temperature is higher (120ºF), EM heating results in a significant temperature rise, hence considerable reduction in oil viscosity. The same holds true for CSS. But in CSS steam is injected. It condenses to water at the end of soaking period, roughly 2600 bbl after each injection period. When the well is opened for production, the production of water (Figure 5.11) affects the permeability for oil. This is not the case with EM heating, since nothing is injected into the reservoir.

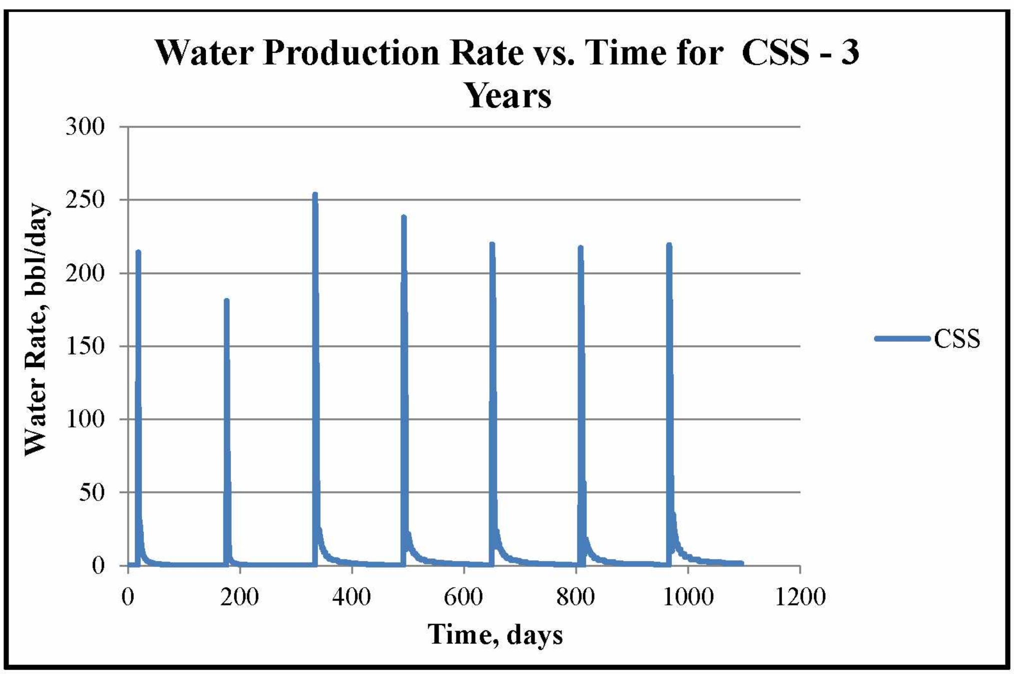

Figure 5.11: Water Production Rate in CSS

3. Also the production of hot water and oil removes considerable heat from the reservoir, which results in a drop of production after a certain period. In EM heating, since heat is continuously supplied and the oil is fairly mobile production continues as more and more oil comes in contact with the heated part of the reservoir.

5.5 Low Reservoir Temperature

5.5.1 Initial Reservoir Temperature of 80°F

Heavy oil reservoirs on the Alaska North Slope have lower temperatures, so to compare the oil production results for both the thermal methods the reservoir temperature was set at 80°F.

5.5.1.1 After 3 Years of CSS

After 3 years of steam injection and soaking, temperature at the injection well increases to 575°F. At 30 ft from the wellbore the temperature increases to 274°F, and 50 ft farther from the wellbore the temperature is 147°F (Figure 5.12).

Oil viscosity near the wellbore reduces to 0.042 cp from an initial viscosity of ~19,000 cp, and 30 ft from the wellbore the viscosity is ~16 cp. At a distance of 50 ft from the well, viscosity is reduced to ~1000 cp (Figure 5.13).

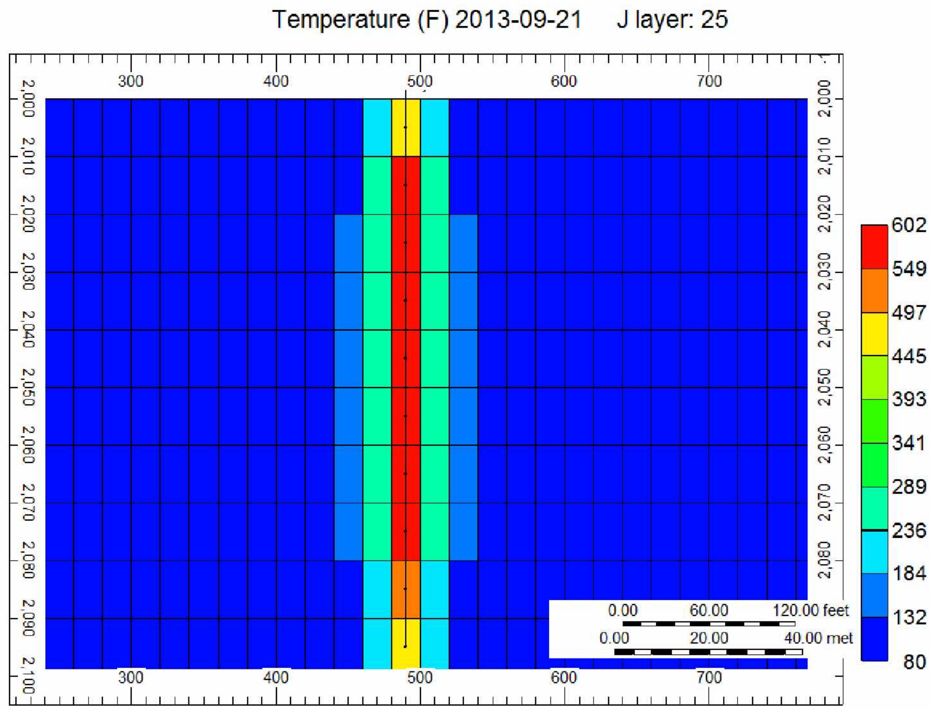

Figure 5.12: Temperature Profile after 3 Years of CSS - Initial Temperature 80ºF

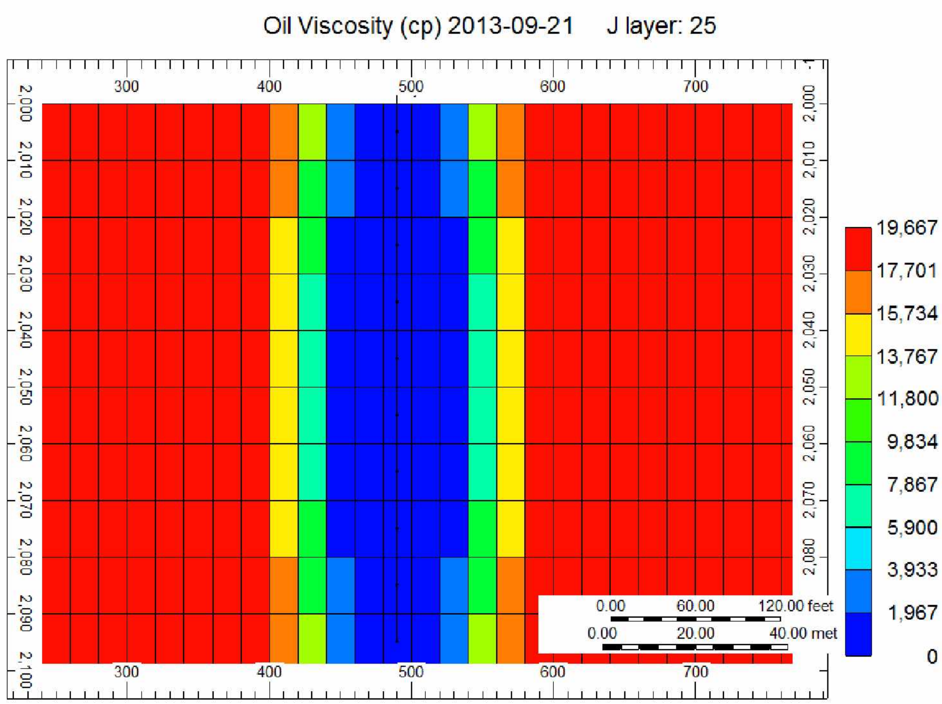

Figure 5.13: Viscosity Profile after 3 Years of CSS - Initial Temperature 80ºF

Figure 5.14 shows the oil production rate for CSS as compared to EM heating. With EM heating over a period of 3 years, 13,300 bbl of oil can be produced, whereas with CSS 18,000 bbl of oil can be produced (Figure 5.15). Thus it can be seen that with both thermal methods, oil production is comparable.

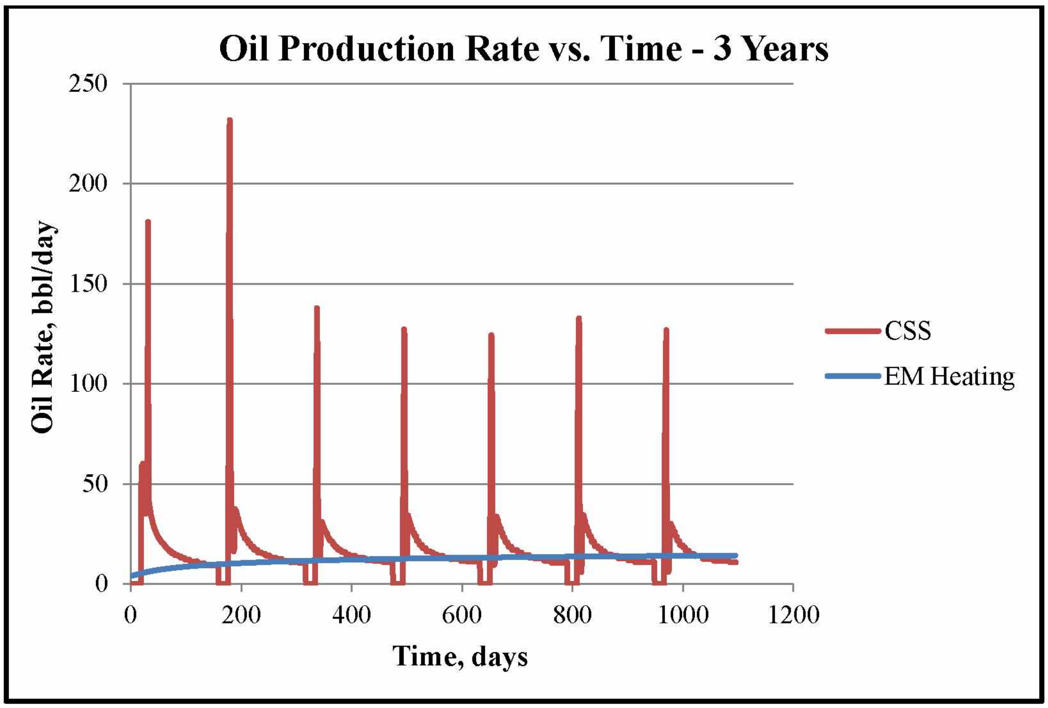

Figure 5.14: Oil Production Rate-Initial Reservoir Temperature 80ºF.

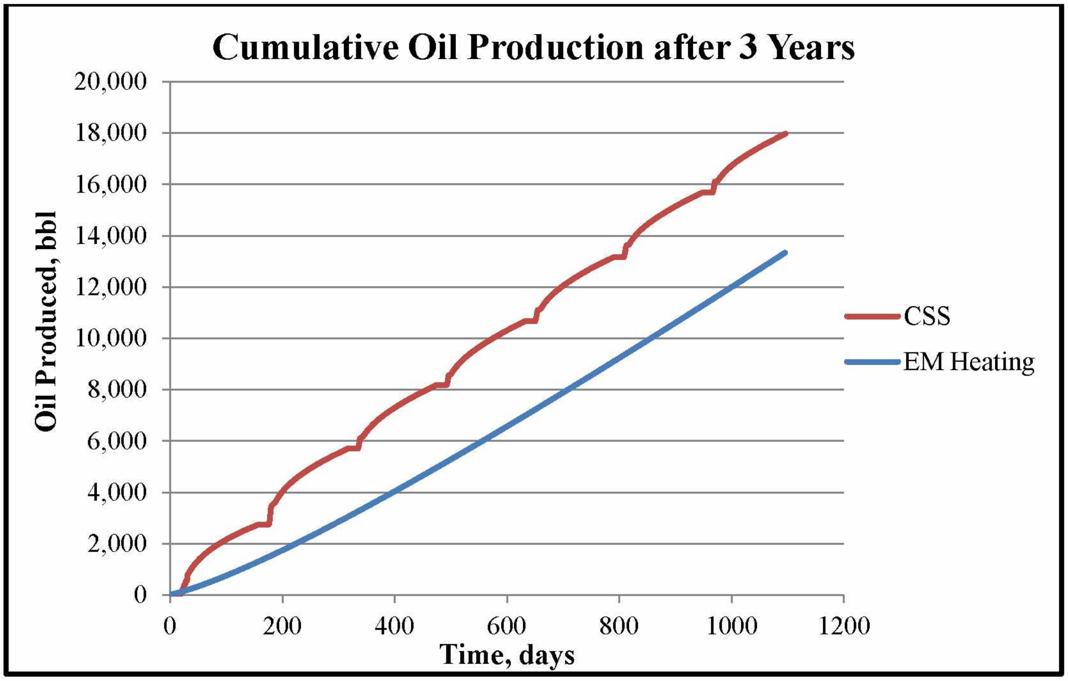

Figure 5.15: Cumulative Oil Produced-Initial Reservoir Temperature 80°F.

5.5.2 Initial Reservoir Temperature of 45°F

The initial reservoir temperature was further reduced to 45°F, to mimic the lower temperature parts of the Ugnu reservoir. The initial oil viscosity at 45°F is very high, in the range of 123,000 cp. The EM power input was kept constant at 100 KW at a frequency of 915 MHz and the heating was done for a period of 5 years. Similar analysis was done with CSS where the steam injection was kept constant at 370 bbl/day.

5.5.2.1 After 5 Years of CSS

After 5 years of steam injection and soaking, the temperature at the injection well increases to a temperature of 615°F. At a distance of 30 ft from the wellbore the temperature increases to 293°F. The temperature is 137°F 60 ft farther from the wellbore (Figure 5.16).

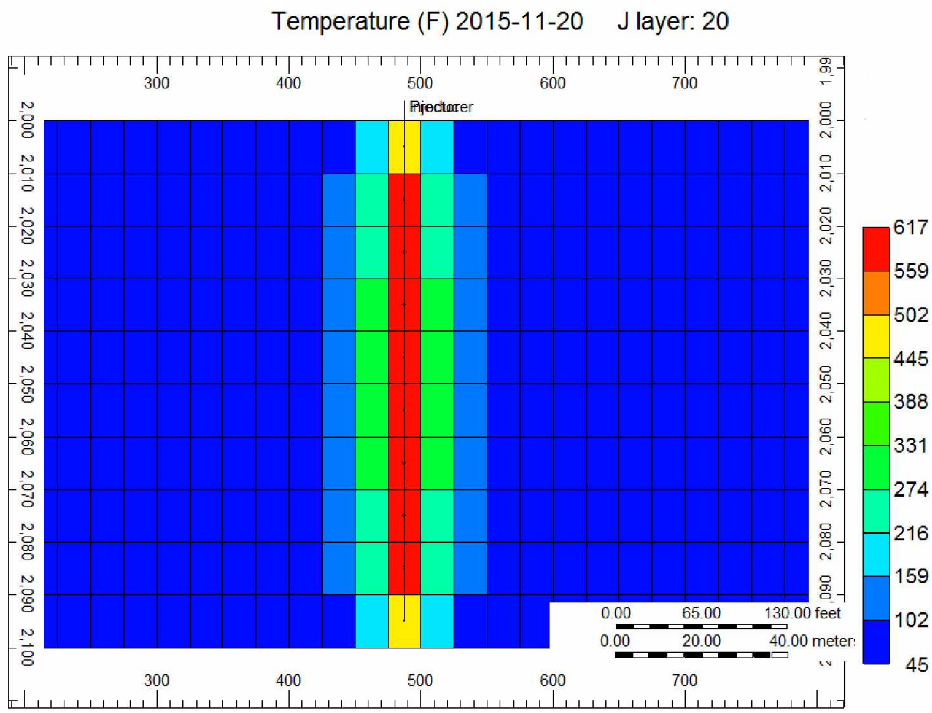

Figure 5.16: Temperature Profile after 5 Years of CSS - Initial Temperature 45ºF

Oil viscosity near the wellbore reduces to 0.03 cp from an initial viscosity of ~123,000 cp, and at a distance of 30 ft from the wellbore it reduces to ~10 cp. At a distance of 60 ft. from the well the viscosity is reduced to ~1400 cp (Figure 5.17).

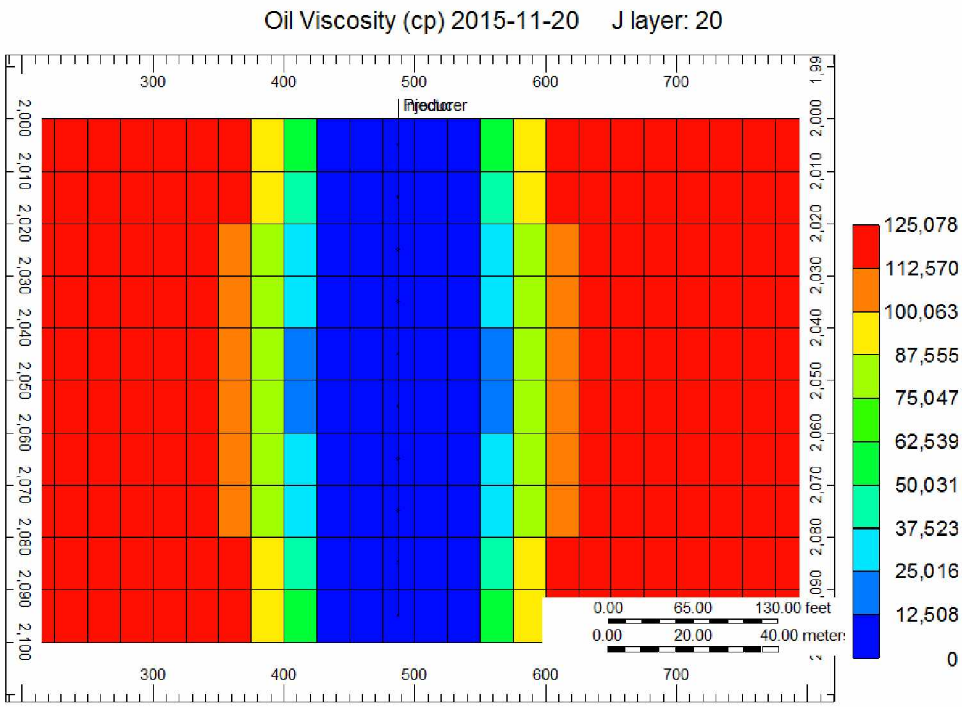

Figure 5.17: Viscosity Profile after 5 Years of CSS - Initial Temperature 45°F

The results showed that with EM heating ~9,000 bbl of oil can be produced, whereas with CSS ~25,000 bbl of oil can be produced over the same time period (Figure 5.18). These results suggest that as reservoir temperature goes down, EM heating becomes less effective as compared to the CSS method of production.

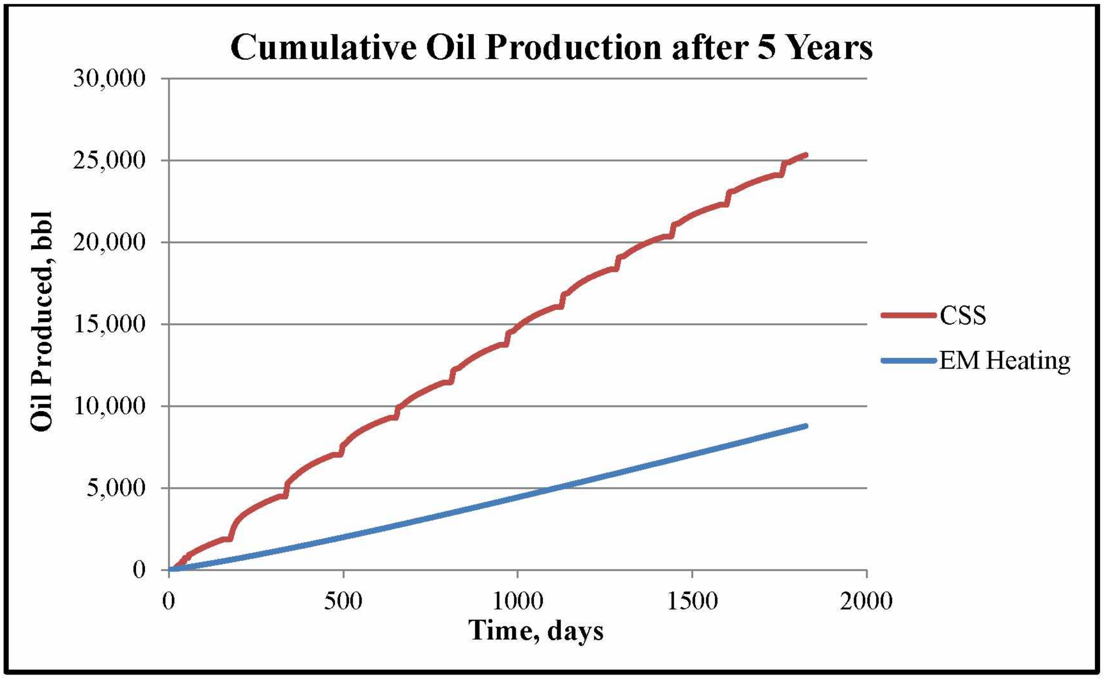

Figure 5.18: Cumulative Oil Produced after 5 Years of Heating-Reservoir Temperature 45°F

5.6 EM Heating Compared to CSS

These results suggest that for reservoirs with very low initial temperature and very high oil viscosity, EM heating for EOR is less effective as compared to CSS. Some possible reasons for this may be:

1. The CSS method shows increased cumulative oil production due to increased oil production rates when the well is opened for production after the end of soaking periods. Initial rates are high because the viscosity of oil is reduced due to the increase in the reservoir temperature. After the initial bump, the oil rate progressively decreases due to the removal of oil and the temperature also reduces which is typical for a CSS process.
2. EM heating does not heat the reservoir deep enough which does not mobilize the oil to improve oil production. It causes sufficient rise in temperatures compared to the initial reservoir temperatures. For a reservoir initially at a temperature of 45°F,

the temperature at a distance of 33 ft from the wellbore increases to 120°F after 5 years of EM heating (Figure 4.26) for example. This is a 166% increase in temperature, but not enough to cause sufficient reduction in oil viscosity. In CSS, steam penetrates more deeply than EM heating and causes significant rise in temperatures. With CSS, temperature rises to 293°F at a distance of 30 ft, very high compared to EM heating.

3. Under the similar pressure constraints (P_i = 1300 psi and BHP = 600 psi), when compared to a reservoir at 120°F with an initial oil viscosity of ~3000 cp, the oil at 45°F at ~123,000 cp is immobile and does not flow towards the wellbore.
4. In addition, since the soaking period in CSS is preceded by a period of steam injection, reservoir pressure near the wellbore also increases to some extent. This increased pressure aids in mobilizing the oil and increasing oil rates when the well is opened for production. Since EM heating is a continuous process, there is no pressure maintenance as we see in CSS.
5. The injection of steam followed by soaking period causes the condensation of steam into hot water that may circulate inside the reservoir and may cause more area to be heated. This might help in increasing the effectiveness of CSS in recovering from reservoirs at very low temperatures.

Hence for very low temperature reservoirs containing oil at a very high viscosity, EM heating can be used as a well stimulation process and can be combined with other methods of EOR. For reservoirs initially at higher temperatures, EM heating can be used as a stand-alone process.

6. LOW FREQUENCY ELECTRICAL HEATING FOR GAS HYDRATE DISSOCIATION

6.1 Introduction to Gas Hydrates

Natural gas hydrates are solid, crystalline, ice-like material that results from the trapping of gases, mainly methane, inside cages of water molecules (Englezos, 1993). Figure 6.1 shows a sample of gas hydrates.

Figure 6.1: A Gas Hydrate Sample

(Science Daily, http://www.sciencedaily.com/releases/2007/02/070221180908.htm)

Gas hydrates are formed when gas molecules (guests) get trapped in water molecules (hosts). There is no chemical bonding between the water and the gas molecule. These gas molecules can be CH_4, C_2H_6, and CO_2 to name a few (Englezos, 1993). Hydrates can form under high pressures or low temperatures. Huge volumes of gas hydrates are estimated to exist at various locations around the globe, as shown in Figure 6.2. It is known that 1 m^3 of hydrates when dissociated releases about 180 std. m^3 of gas (Islam, 1991; Garg et al., 2008). This makes gas hydrates a huge potential as a future energy resource.

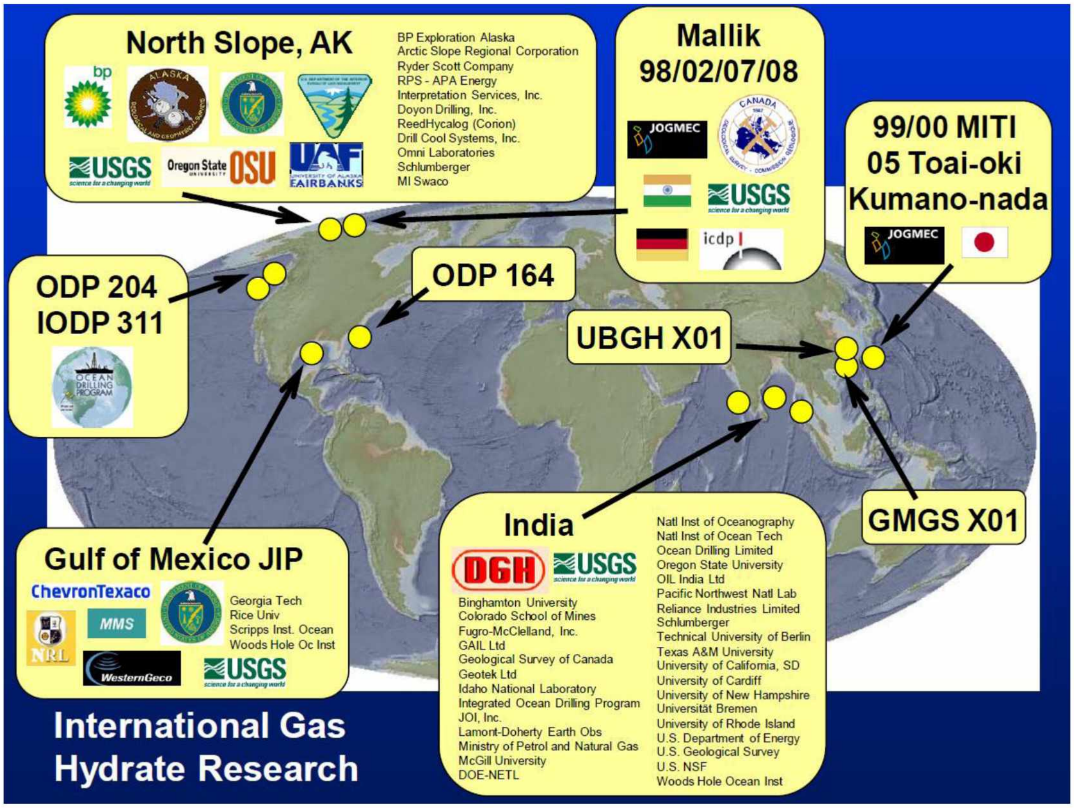

Figure 6.2: World Distribution of Gas Hydrates

(Courtesy Collett, Search and Discovery Article #80026, 2008)

6.2 Gas Hydrate Production Methods

Various methods to produce gas from gas hydrate formations are proposed:

- Depressurization
- Thermal Stimulation
- Inhibitor Injection

Figure 6.3 depicts the various methods of producing from gas hydrate formations.

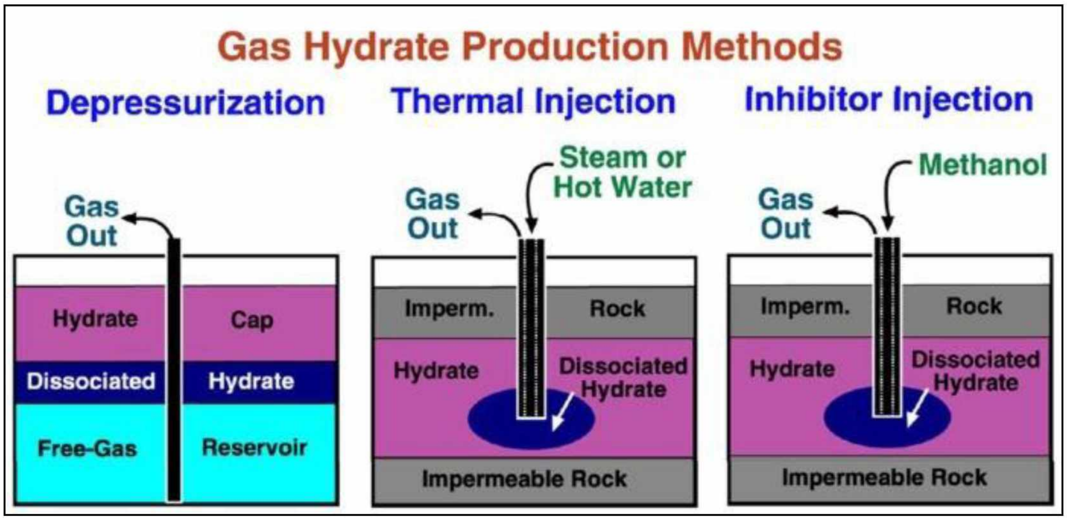

Figure 6.3: Methods to Produce Gas from Gas Hydrates

(Crain's Petrophysical Handbook, http://www.spec2000.net/17-gashydrate.htm)

The depressurization method of producing from gas hydrate reservoirs is attractive and can effectively dissociate hydrates. But since the dissociation of hydrates is endothermic in nature, it can lead to a decrease in reservoir temperature potentially resulting in hydrate reformation that would hamper the production of gas from gas hydrates (Garg et al., 2008). Chemical inhibitors such as methanol or glycol can be used to dissociate hydrates, but these methods of production are considered slow and inefficient in the recovery of natural gas (Islam, 1991). In addition there are cost and environmental issues. Thermal methods for gas hydrate dissociation can be used to heat the hydrate reservoir and keep it above hydrate reformation temperature, thus preventing hydrate reformation and choking of production wells (Islam, 1991).

One method of in-situ heating studied for some time now and explained earlier (section 2.1.1) is low frequency electrical heating. In this method electrodes are placed in the reservoir and a potential difference is applied across them. The presence of connate water helps in the conduction of electric current, which in turn generates heat as per Equation 2.1. The presence of water is crucial for this mode of heating as it acts as the conductive medium for electric current; reservoir temperature at any time during heating should not exceed water vaporizing temperature (Baylor et al., 1990).

6.3 Electrical Heating Model for Gas Hydrate Dissociation

Using CMG-STARS, the effect of electrical heating on gas hydrate dissociation was studied. CMG-STARS has the capability to simulate low frequency electrical heating where we can specify the placement of electrodes, power input, and the applied voltage. The model is built. Then the keywords for electrical heating, the placement of electrodes, and the important electrical parameters of the formation have to be written into the data file, as CMG does not have any explicit commands to activate electrical heating. As mentioned earlier, the presence of water is important for this mode of electrical heating and should not be allowed to vaporize. To prevent connate water from vaporizing, CMG has a no-flash option that switches off the electrical heating once the specified temperature limit is reached. Using this option, we can be sure that formation water is always present and that electrical heating will continue.

Novruzaliyev (2011) built a radial grid model (Figure 6.4–Figure 6.6) to study the production of natural gas from a gas hydrate reservoir using depressurization technique and the properties shown in Table 6.1. Table 6.2 shows the initial fluid saturation distribution.

Table 6.1 Reservoir and fluid properties used for gas hydrate model (from Novruzaliyev, 2011)

Property	**Value**
Radius	500 ft
Reservoir Depth	1900 ft
Reservoir Thickness	430 ft
Initial Reservoir Pressure	975 psi
Initial Temperature	Top - 41ºF
	Bottom - 48ºF
Porosity	20%
Permeability	H - 50 mD
	V - 10 mD
Perforation Depth	1940 - 1960 ft (20 ft)
Hydrate Gas Contact	2050 ft
Gas Water Contact	2080 ft

Table 6.2 Initial fluid saturations for gas hydrate model (from Novruzaliyev, 2011)

	Hydrate (S_h), %	**Gas (S_g), %**	**Water (S_w), %**
Hydrate Zone	31	14	55
Free Gas Zone	0	45	55
Water Zone	0	0	100

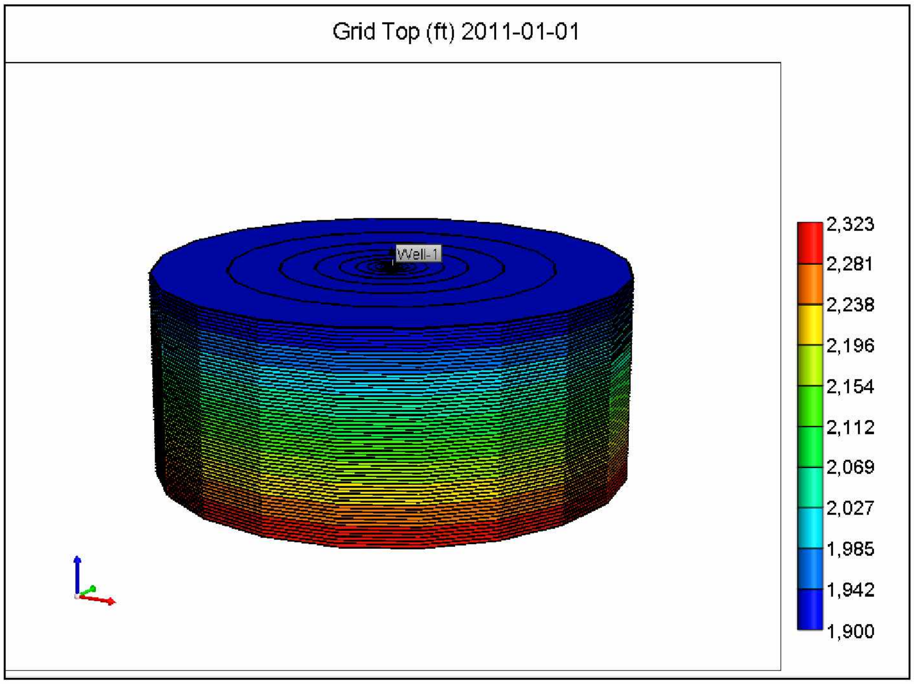

Figure 6.4: Gas Hydrate Radial Grid Model (ft.) using CMG-STARS
(Novruzaliyev, 2011)

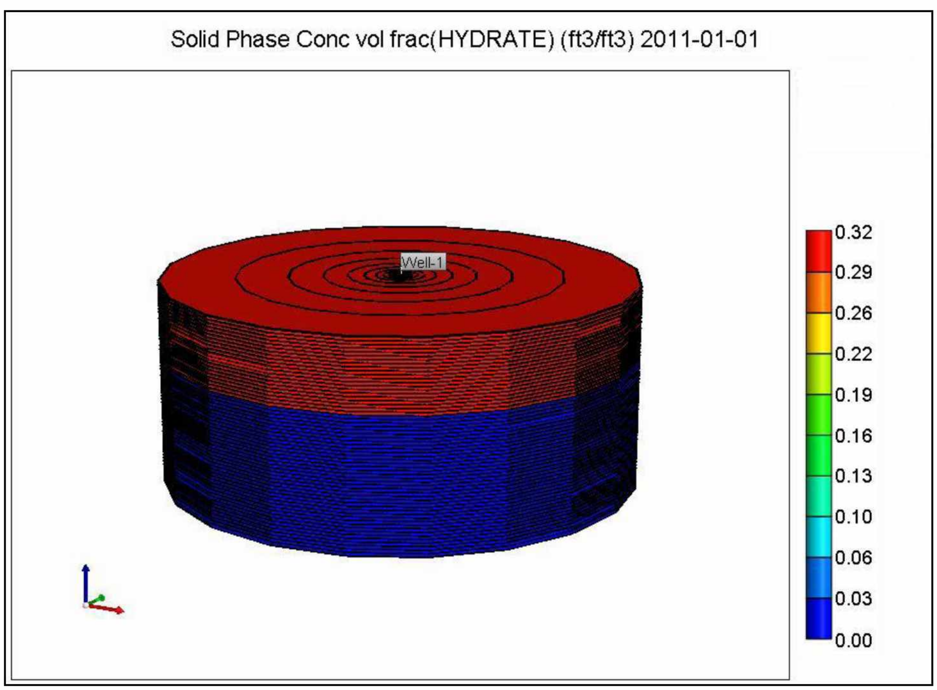

Figure 6.5: Initial Hydrate Concentrations (ft^3/ft^3)
(Novruzaliyev, 2011)

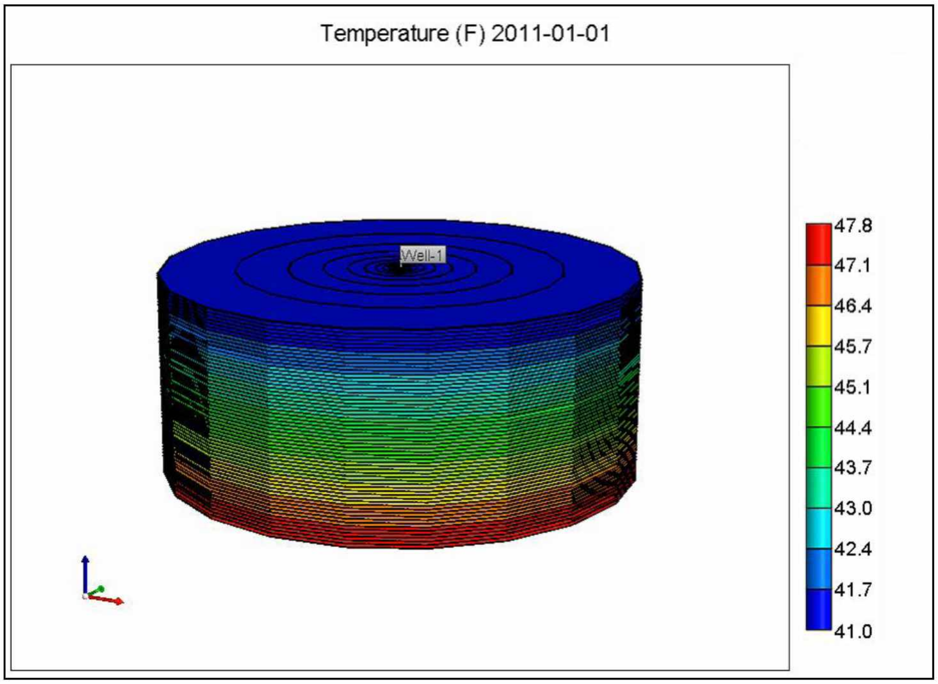

Figure 6.6: Initial Temperature Profile (ºF)
(Novruzaliyev, 2011)

The well was drilled in the hydrate zone and two scenarios were studied where the gas production rate was kept constant at 10 Mscf/day and 30 Mscf/day (Novruzaliyev, 2011). Production was simulated for a period of 15 years. The results showed that due to the reformation of gas hydrates near the wellbore the well was choked, which inhibited further gas production, and the gas production rate dropped sharply (Novruzaliyev, 2011). To produce continuously from these wells, a heating mechanism must be applied to keep the reservoir above hydrate reformation temperature to prevent well choking. Using CMG-STARS, electrical heating was applied to these models and gas production rate and cumulative gas produced were compared for the two cases.

6.4 Results and Discussion

6.4.1 Case 1: Gas Production Rate of 10 MSCF/DAY

In the first case, the gas production rate was kept constant at 10 Mscf/day. The model was run for a period of 15 years (Novruzaliyev, 2011). The results showed that after a period of 9.8 years, the rate dropped to 80 Scf/day (Figure 6.7). Since the well was open for production, the well produced constantly with the gas production rate gradually rising. After 15 years the rate increased to 5.7 Mscf/day (Novruzaliyev, 2011).

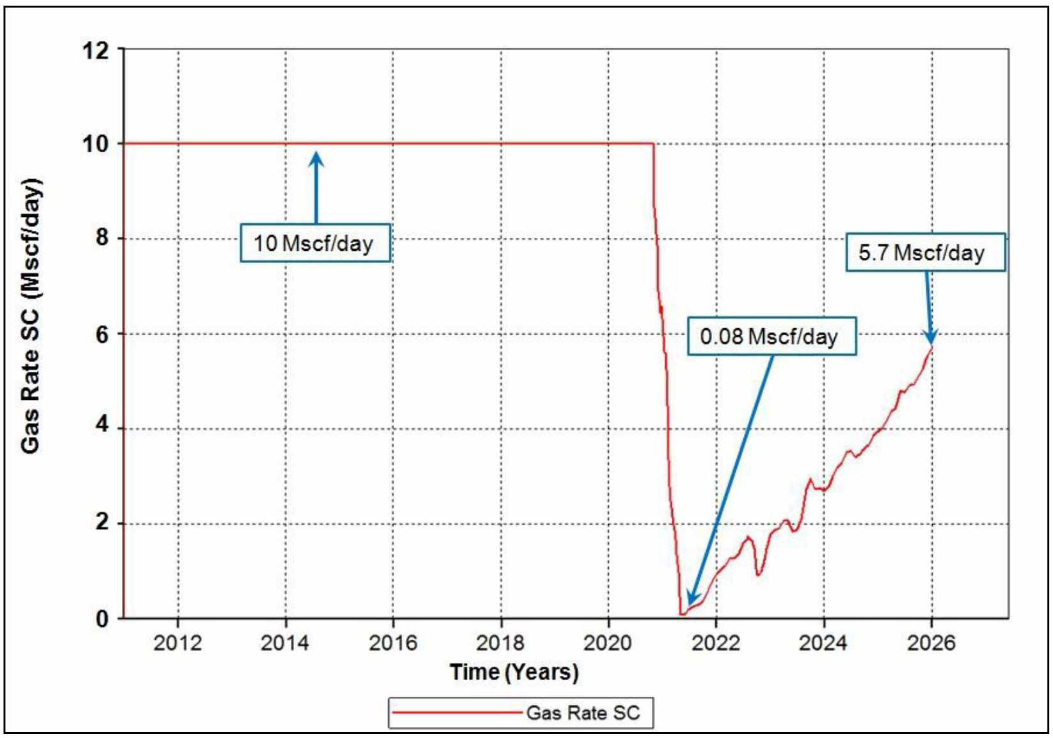

Figure 6.7: Gas Production Rate for Case 1 (10 Mscf/day) without Electrical Heating (Novruzaliyev, 2011)

The main reason for the observed decline in production was hydrate reformation around the perforations and increasing concentration of hydrates (Novruzaliyev, 2011) (Figure 6.8).

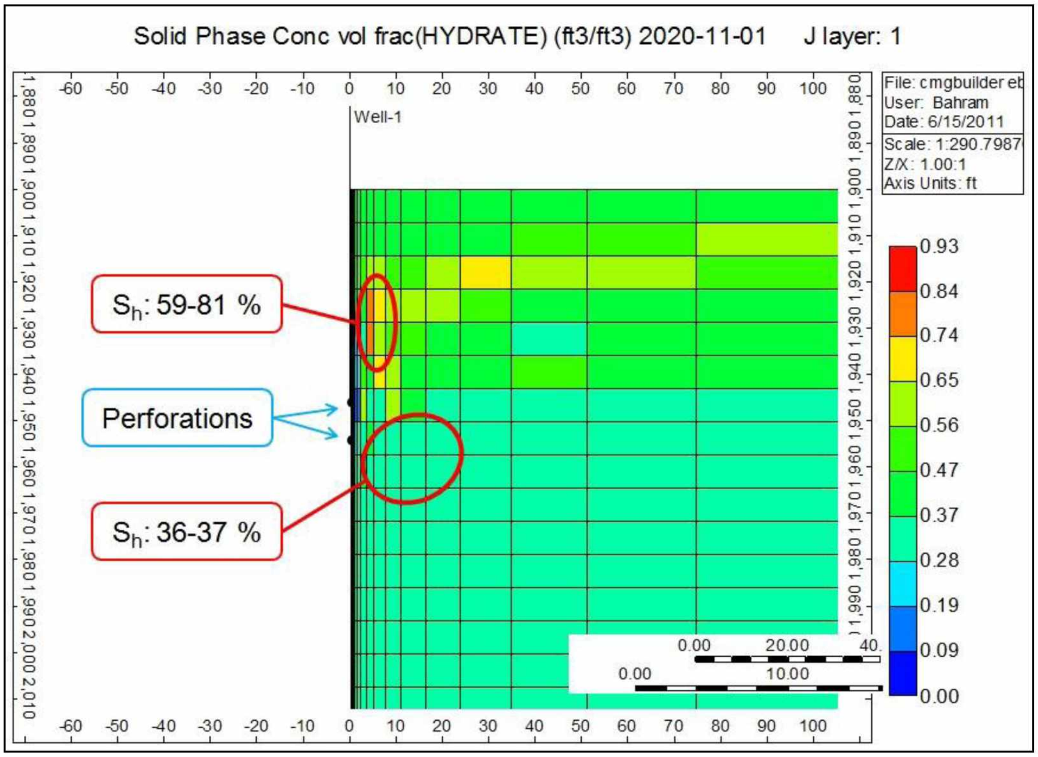

Figure 6.8: Hydrate Saturation after 9.8 Years of Production at 10 Mscf/day (Novruzaliyev, 2011)

To maintain constant gas production electrical heating was added to Novruzaliyev's (2011) model and the increase in gas production was studied. The input power was limited to 10 KW with the no-flash option active, setting it to less than the vaporizing temperature of water. The potential electrode was placed at the producing well from layers 4 through 10. Ten feet from the production well in the radial direction, layers 4 through 10 were assigned ground potential (earth electrode) (Figure 6.9). The result showed that with the addition of electrical heating, the production rate of 10 Mscf/day could be sustained for the entire period of run (i.e., 15 years) (Figure 6.10) without hydrate reformation near the wellbore due to high temperatures, which inhibit hydrate reformation.

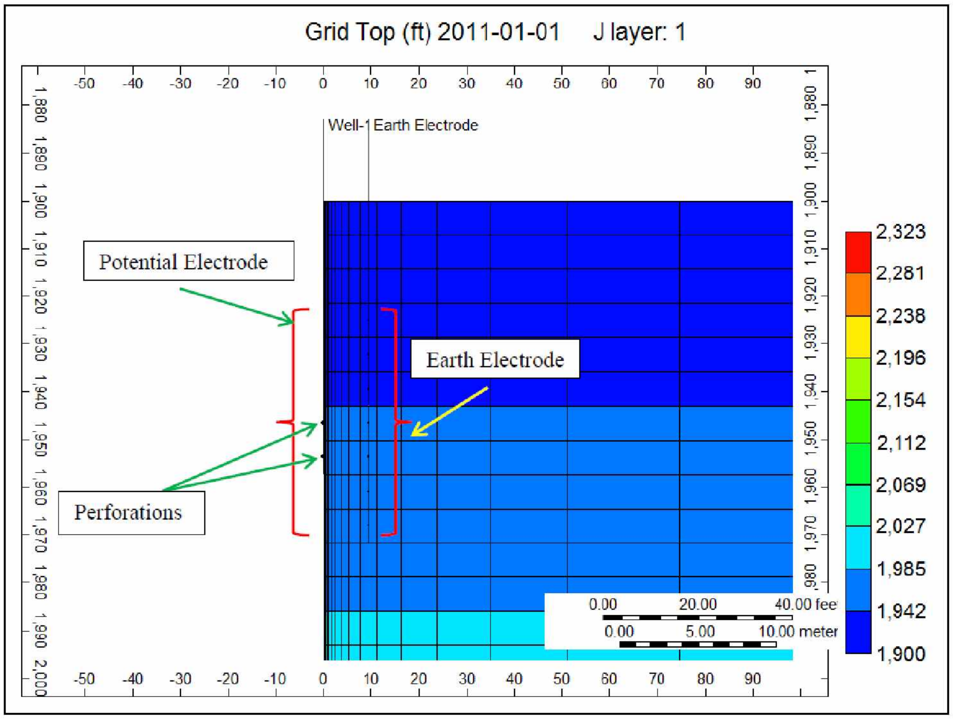

Figure 6.9: Electrode Configuration for Low Frequency Electrical Heating for Gas Hydrates

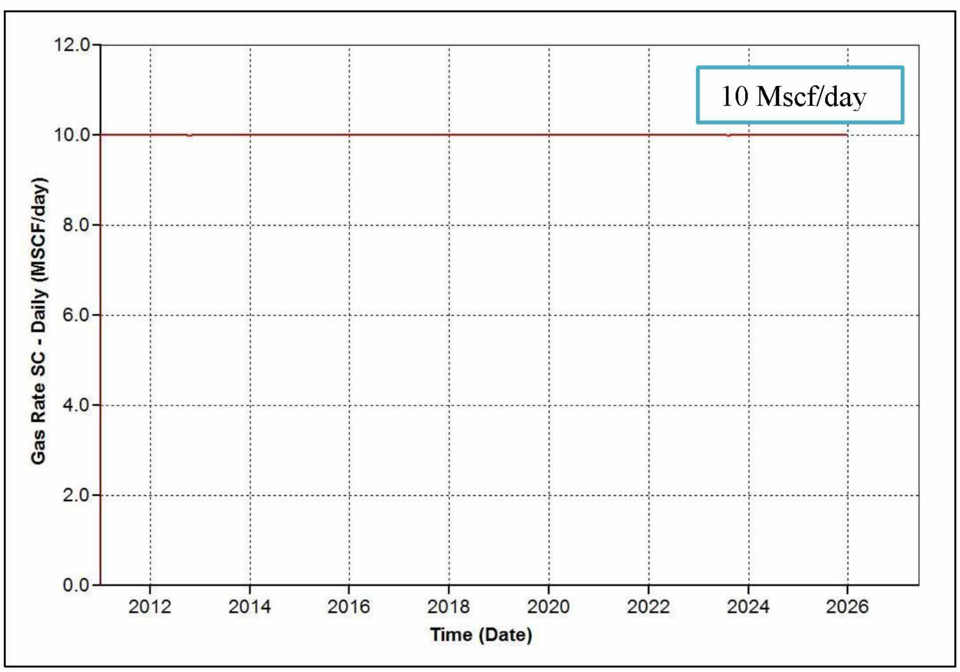

Figure 6.10: Gas Production Rate for Case 1 (10 Mscf/day) with Electrical Heating

With application of electrical heating, a gas production rate of 10 Mscf/day remains constant, without showing any decline due to hydrate reformation. Hence the cumulative gas produced throughout the simulation period is higher compared to production due to depressurization alone, with no heating, as studied by Novruzaliyev (2011). With electrical heating the cumulative gas produced was 54.7 MMSCF over a period of 15 years, without heating it was 36.7 MMSCF (Figure 6.11). Thus electrical heating results in additional production of 18 MMSCF of gas over 15 years.

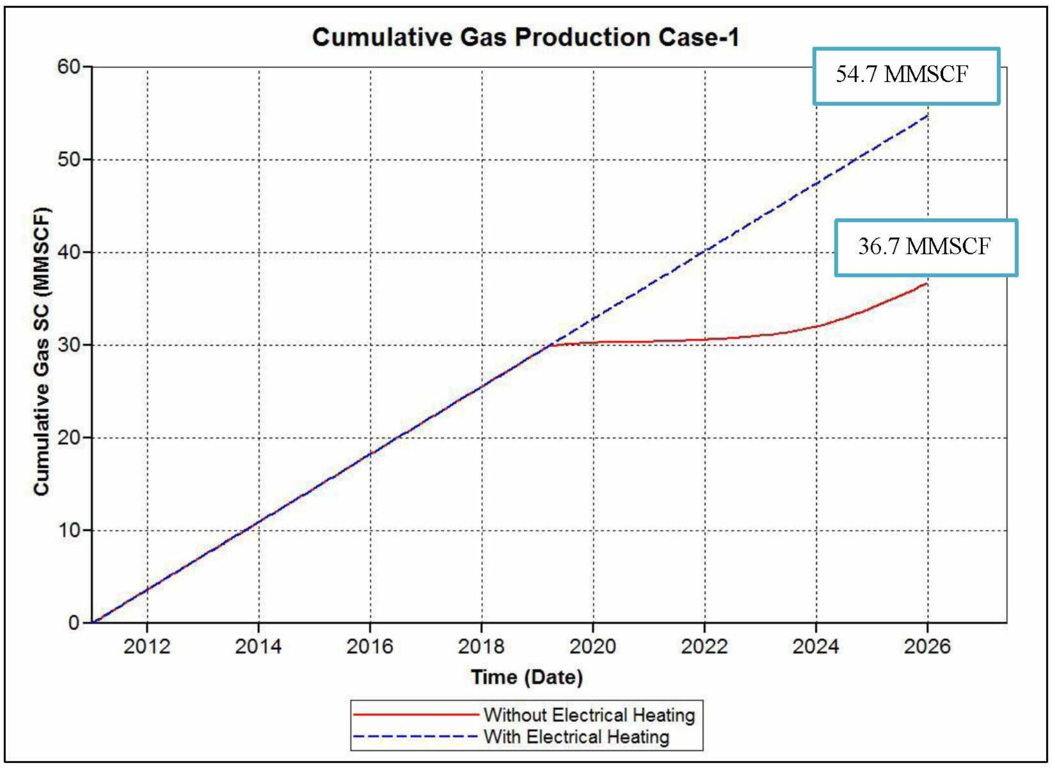

Figure 6.11: Cumulative Gas Productions with and without Electrical Heating

After 15 years of electrical heating, temperatures near the wellbore increases to 163°F. At a distance of 8 ft from the wellbore the temperature increases to 65°F (Figure 6.12). It can be seen that the temperature near the wellbore increases above reservoir temperature, preventing hydrate reformation, and thus preventing choking of the well. This enables continuous gas production.

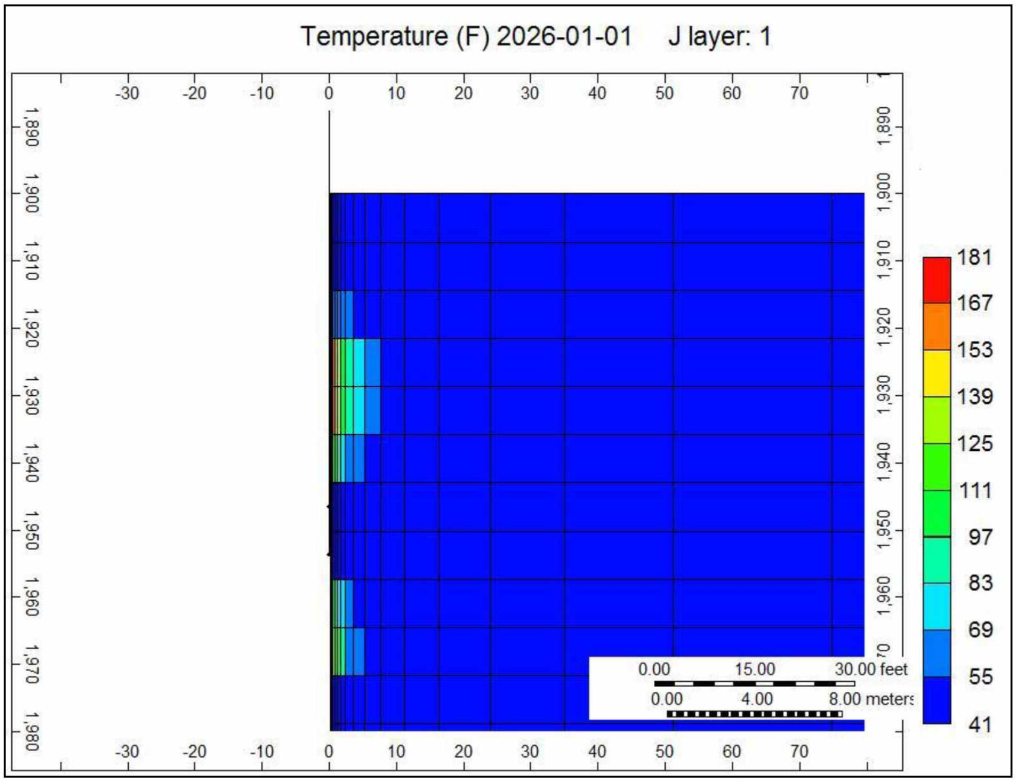

Figure 6.12: Temperature (ºF) Profile near the Wellbore with Electrical Heating

Figure 6.13 shows hydrate concentration near the wellbore after 9.8 years of production with application of electrical heating. Hydrate concentration near the wellbore is almost zero.

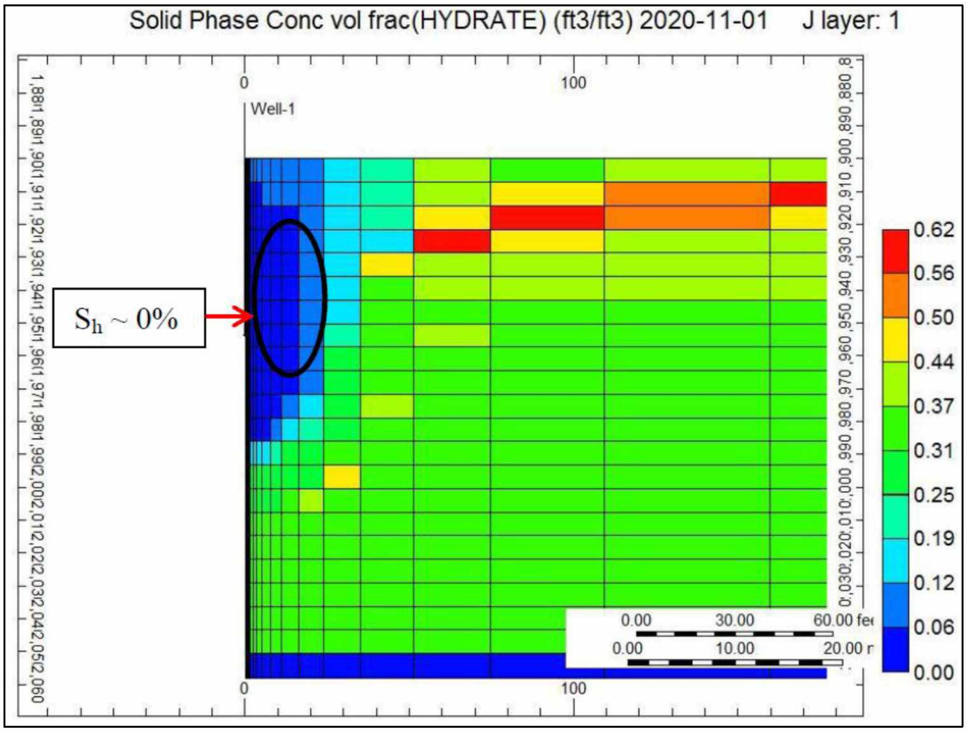

Figure 6.13: Hydrate Saturation after 9.8 Years of Production with Electrical Heating

With depressurization alone, hydrate concentration near the wellbore increases after the end of 15 years due to hydrate reformation. Hydrate concentration varies from 25–44% near the wellbore (Figure 6.14). When electrical heating is applied, hydrate concentration reduces to zero near the wellbore region (Figure 6.15) and no choking is observed.

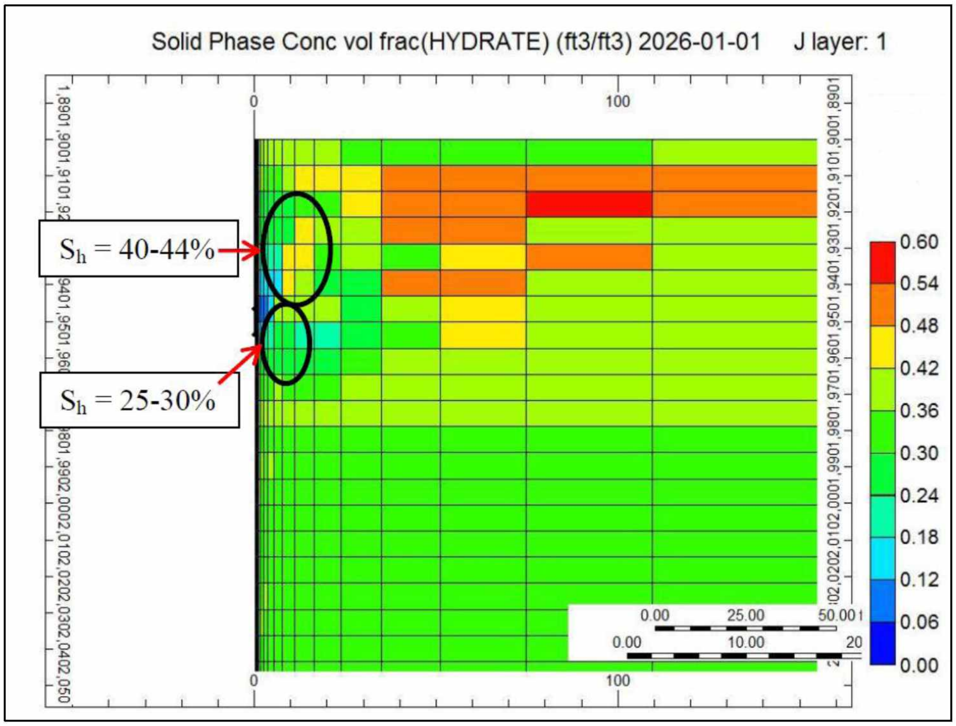

Figure 6.14: Hydrate Saturation after 15 Years of Production without Electrical Heating (Novruzaliyev, 2011)

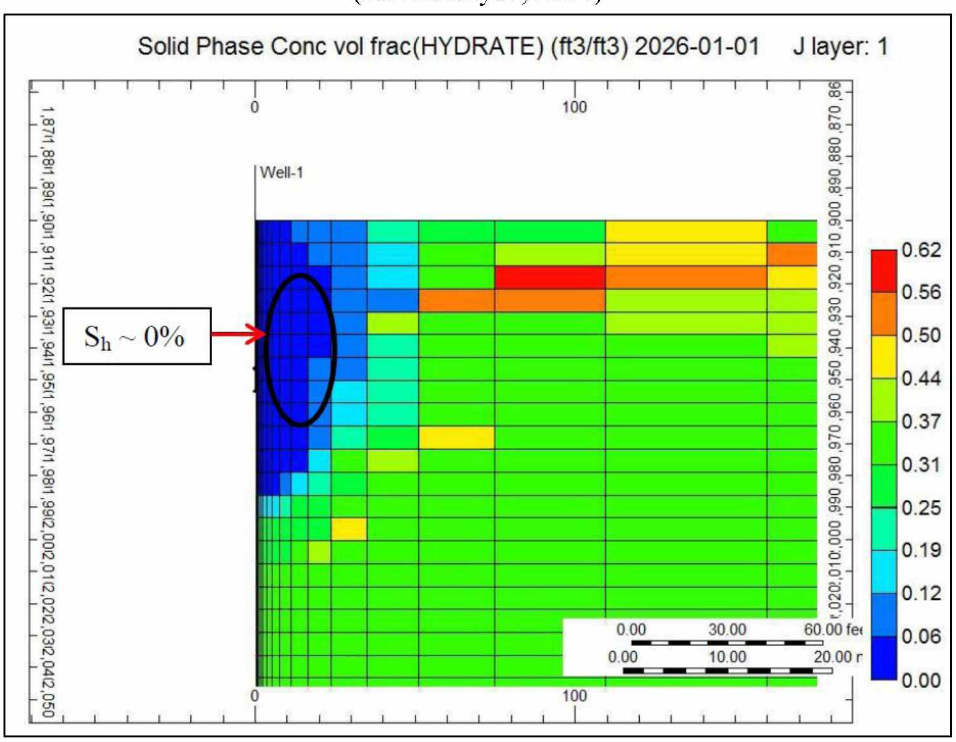

Figure 6.15: Hydrate Saturation after 15 Years of Production with Electrical Heating

6.4.2 Case 2: Gas Production Rate of 30 MSCF/DAY

In Case 2 the gas production rate was increased to 30 Mscf/day to study choking of the well and the effect of increased production rate on hydrate reformation (Novruzaliyev, 2011). Results showed that the well in this case choked faster. For Case 2 the gas production rate declined sharply after 5.8 years of production to 1.6 Mscf/day then gradually rose to 13.2 Mscf/day after the end of 15 years (Novruzaliyev, 2011) (Figure 6.16). Hydrate concentration near the wellbore after 5.8 years of production is shown in Figure 6.17.

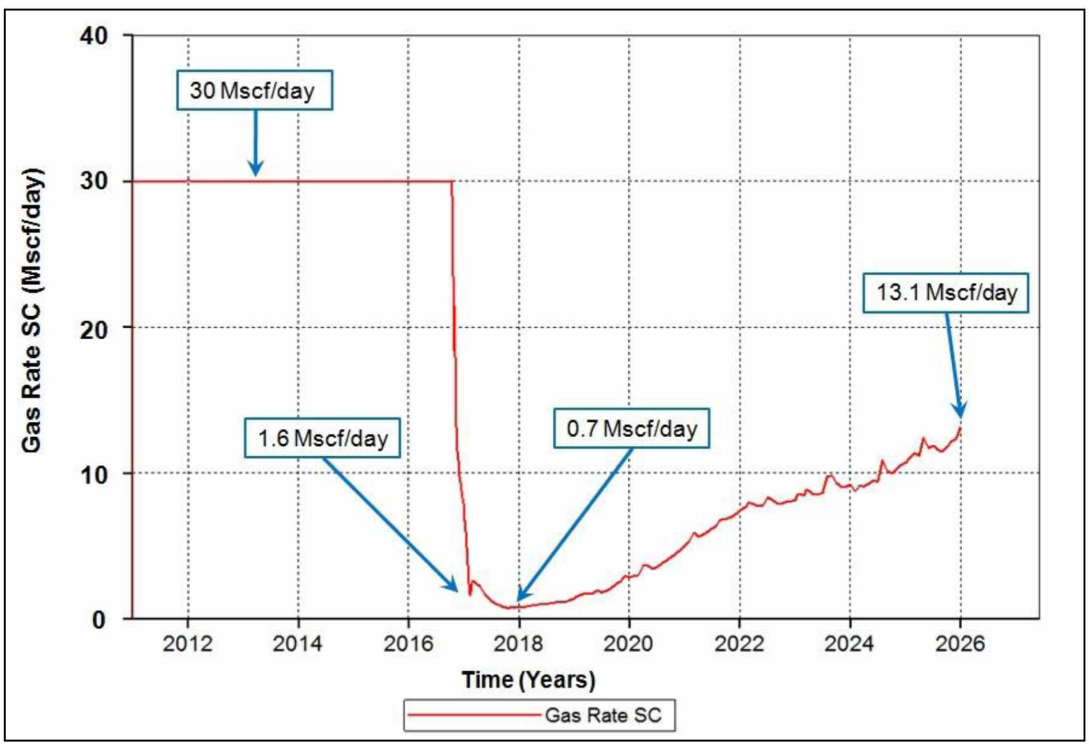

Figure 6.16: Gas Production Rate for Case 2 (30 Mscf/day) without Electrical Heating (Novruzaliyev, 2011)

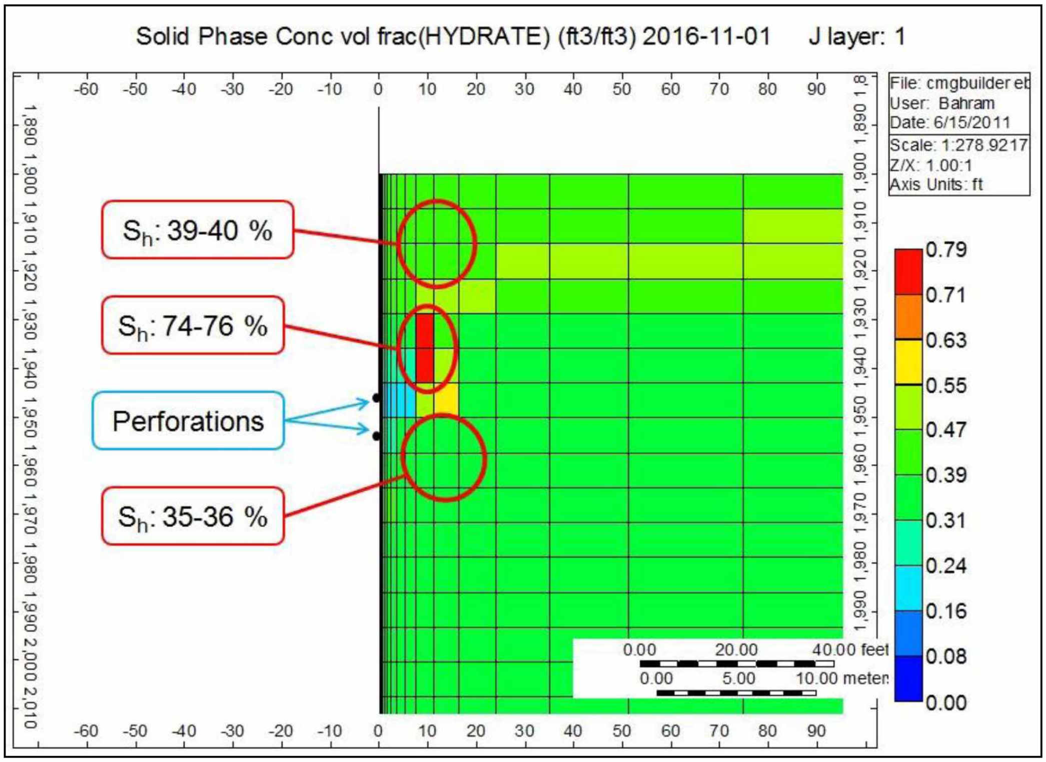

Figure 6.17: Hydrate Saturation after 5.8 Years of Production at 30 Mscf/day (Novruzaliyev, 2011)

In an approach similar to Case 1, electrical heating was added to the model in Case 2 to study gas production at a higher rate. The results showed that the gas production rate could be maintained at the desired rate of 30 Mscf/day for the entire run of the simulation with the addition of electrical heating (Figure 6.18). Since the gas production rate could be maintained at the desired rate of 30 Mscf/day and did not show any decline with the application of electrical heating, the cumulative gas produced was much higher. With electrical heating the cumulative gas produced over a period of 15 years was 164.3 MMSCF, which in the case of depressurization alone was 77.8 MMSCF (Figure 6.19). Thus with the application of electrical heating an extra 86.5 MMSCF of gas was produced.

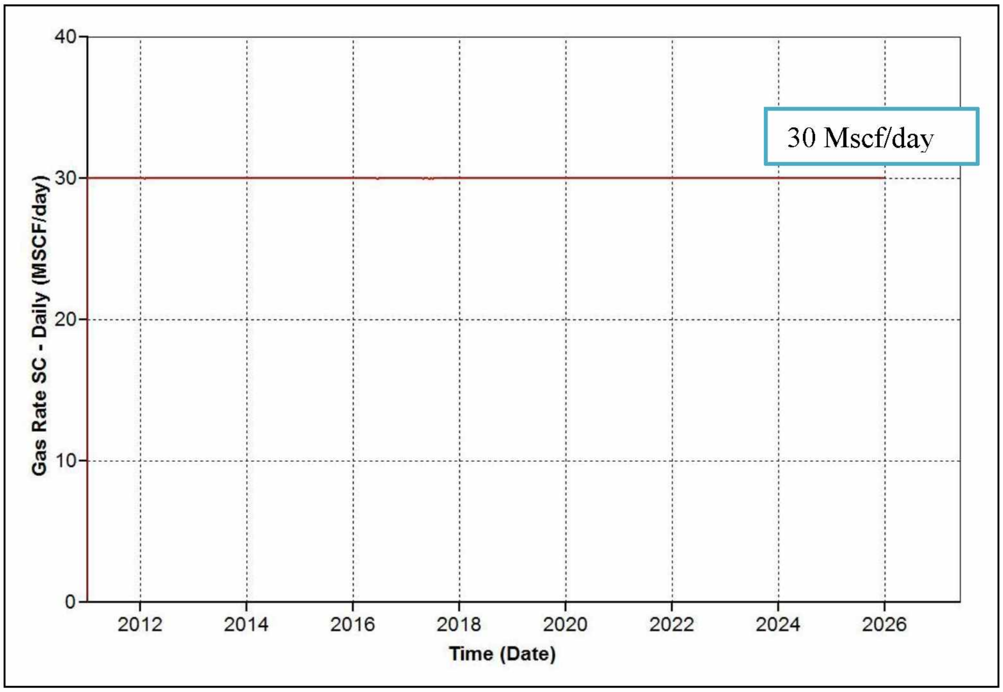

Figure 6.18: Gas Production Rate for Case 2 (30 Mscf/day) with Electrical Heating

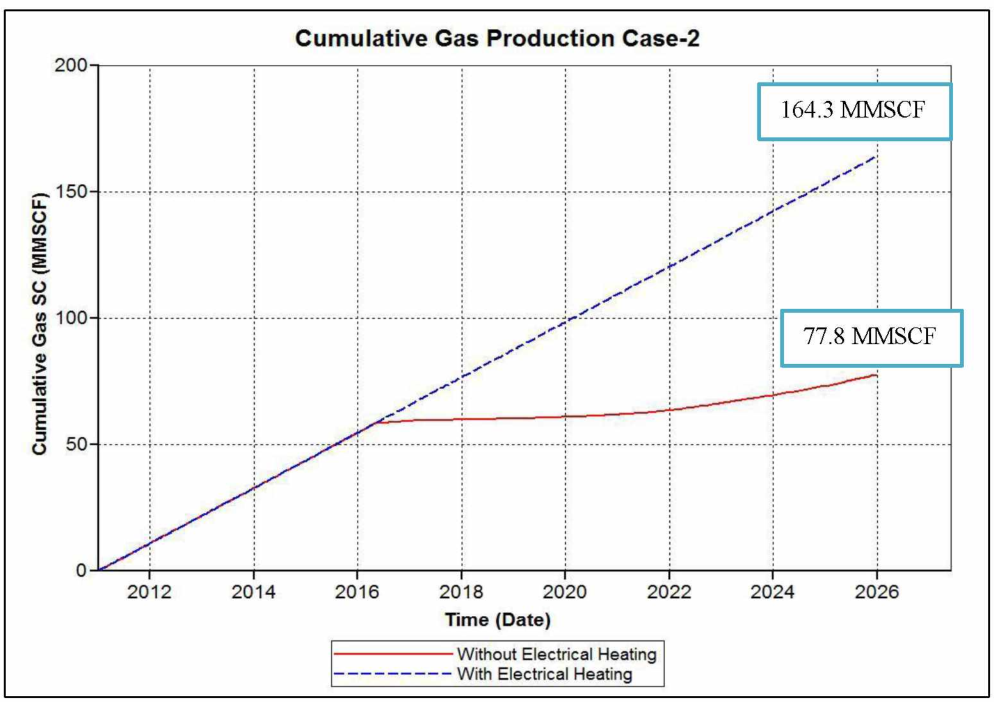

Figure 6.19: Cumulative Gas Productions with and without Electrical Heating

Figure 6.20 shows the temperature distribution near the wellbore with the application of electrical heating. Near the production well the temperature rises to 150ºF. At a distance of 6 ft the temperature rises to 60ºF, which inhibits hydrate formation and hence choking of the well. Hydrate concentration near the wellbore after 5.8 years is reduced to zero (Figure 6.21).

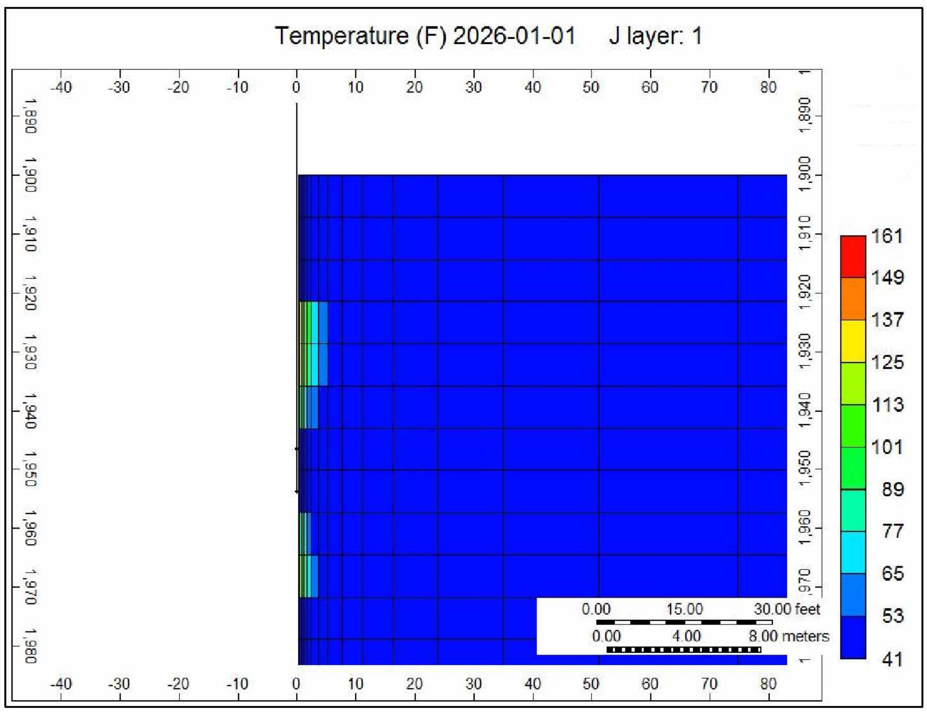

Figure 6.20: Temperature (ºF) Profile after 15 Years of Gas Production with Electrical Heating

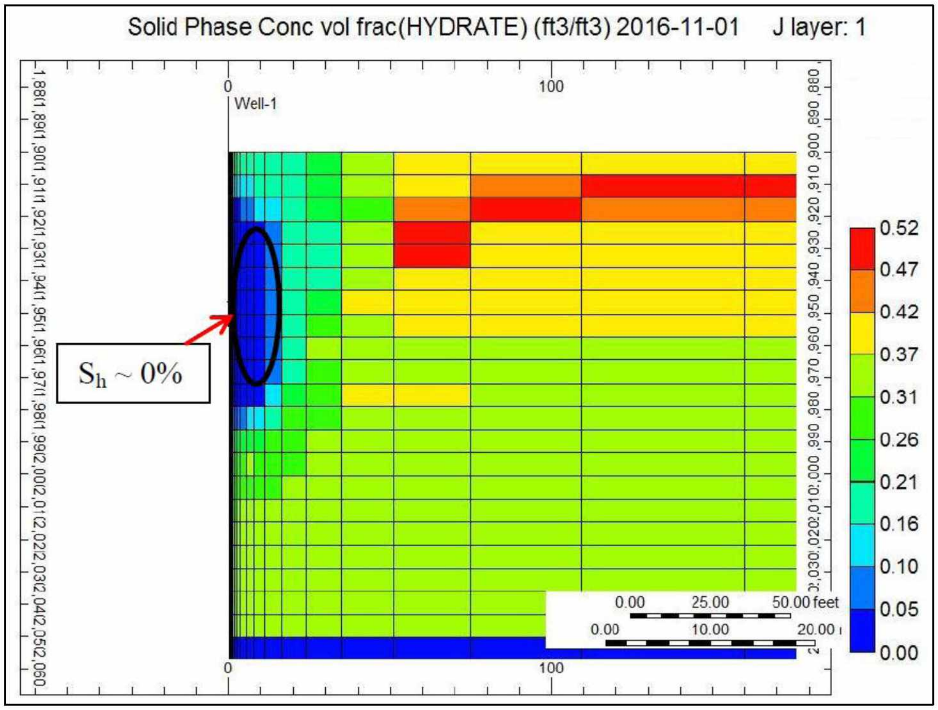

Figure 6.21: Hydrate Saturation after 5.8 Years of Production with Electrical Heating

With depressurization alone, hydrate concentration near the wellbore increases after the end of 15 years due to hydrate reformation. The hydrate concentration varies from 20–35% near the wellbore (Figure 6.22). But when electrical heating is applied, the hydrate concentration reduces to zero near the wellbore region (Figure 6.23), and no choking is observed.

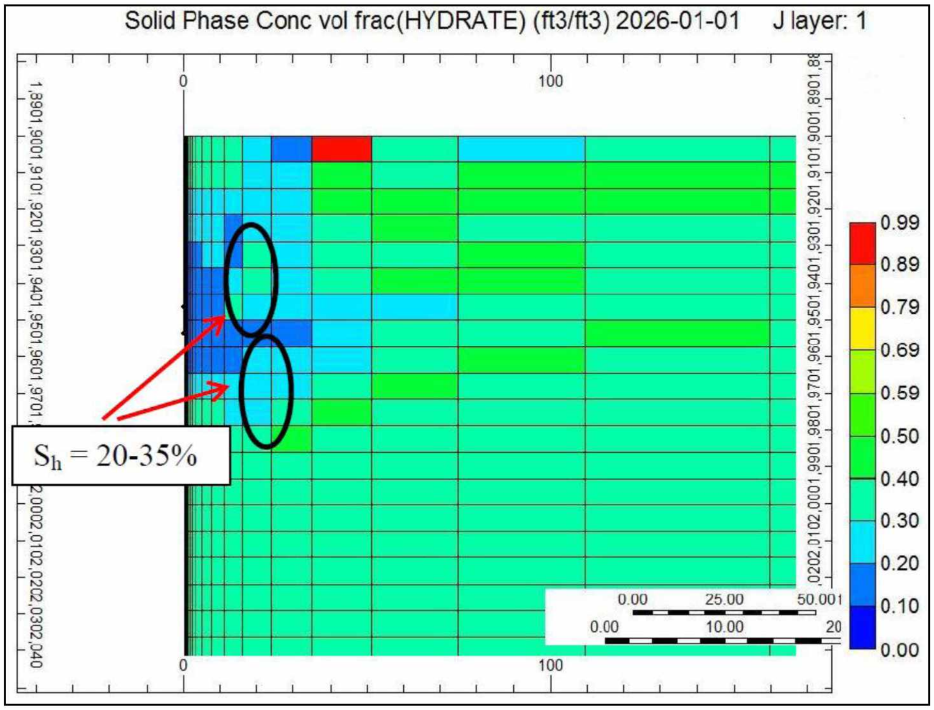

Figure 6.22: Hydrate Saturation after 15 Years of Production without Electrical Heating (Novruzaliyev, 2011)

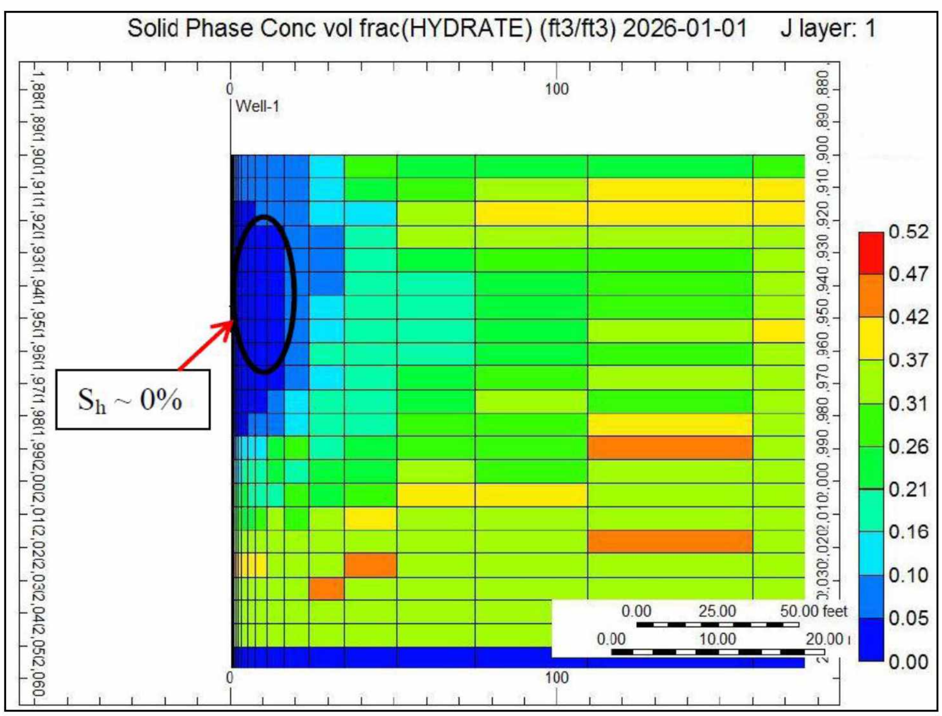

Figure 6.23: Hydrate Saturation after 15 Years of Production with Electrical Heating

7. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

7.1 Summary

This research showed how electrical energy can be used to produce and/or enhance production of unconventional hydrocarbon resources, namely heavy oil deposits and gas hydrates. This work highlighted how EM heating can be applied to produce from heavy oil reservoirs and what advantages in-situ heating has over conventional thermal methods of heavy oil production in arctic conditions. An axisymmetric 2D model was built using COMSOL to highlight the effect of EM heating and its effect on heavy oil production. EM heating was also compared to CSS method of production.

A variant of EM heating, low frequency resistive heating, also can be employed to produce gas from gas hydrate deposits. Earlier studies have shown that with depressurization alone, production of gas from gas hydrates cannot be sustained due to choking of the well because of hydrate reformation. However, with electrical heating combined with depressurization, gas production can be sustained longer and more gas can be produced.

7.2 Conclusions

1. A 2D axisymmetric EM heating model was built in COMSOL. Assuming no heat loss to overburden and under-burden, the reservoir temperature can be significantly increased as a result of EM heating. EM heating causes substantial rise in reservoir temperature around the near-wellbore region, and with continuous use EM heating penetrates deep into the reservoir.
2. Assuming only oil is present in the reservoir; EM heating can increase the oil production rate from heavy oil reservoirs initially at higher temperatures (i.e., 120°F) by more than 250% by the end of first year. This increase is approximately 340% by the end of the third year of heating. Over a period of 3 years, cumulative oil production can be greatly increased.

3. EM frequency and input power are the two important parameters that affect EM heating. With increase in frequency the heating rate increases, but the depth of heat penetration decreases.

4. With increase in power, there is much higher increase in temperature and more oil produced.

5. Sensitivity analysis was conducted with different combinations of power and frequency. Two EM frequencies, 915 MHz and 2450 MHz, are typically used for industrial purposes in the microwave region. It was concluded that for the chosen reservoir properties and 120°F initial reservoir temperature, 70 KW of input power and 915 MHz of applied frequency made the optimum combination based on a comparison of cumulative oil produced over a 3-year heating period.

6. The effect of EM heating was studied on reservoirs with low initial temperatures in the range of 45°F–100°F, as on the North Slope of Alaska. EM heating can be used to generate heat downhole and produce from these reservoirs where oil viscosity is >10,000 cp.

7. The effect of EM heating was studied for 3 different reservoir temperatures: 120°F, 80°F, and 45°F. Results showed that the effectiveness of EM heating decreases as initial reservoir temperature decreases.

8. The amount of oil produced decreases with EM heating for reservoirs at lower initial temperatures. Since the initial temperatures are very low and the oil is immobile, greater energy is required to increase reservoir temperatures significantly. This must be economically justified.

9. EM heating was compared with Cyclic Steam Stimulation and the results showed that given the same energy input, EM heating can be more effective in producing from heavy oil reservoirs that are at higher temperatures. However, the effectiveness of EM heating decreases as reservoir temperature decreases.

10. For reservoirs at lower initial temperatures, EM heating can be used to stimulate the near-wellbore area and it can be combined with other EOR methods of production.

11. Due to the endothermic nature of gas hydrate dissociation, gas production from such reservoirs resulted in reservoir cooling, which accelerated hydrate reformation near the wellbore. With the application of electrical heating, the near-wellbore region can be maintained above hydrate reformation temperature. In gas hydrate reservoirs, gas production can be sustained over longer periods, without choking of the well.

12. Two cases were studied where the rates were kept constant at 10 Mscf/day and 30 Mscf/day, respectively. With the application of electrical heating, it was shown that the desired rates could be maintained for the entire period of run, whereas without the heating in place, the gas production rate dropped sharply after 9.8 years for Case 1 and after 5.8 years for Case 2.

13. With electrical heating, the hydrate concentration near the wellbore was reduced considerably. Heating also prevented hydrate reformation. There was no case of choking of the well and reduction in gas production from gas hydrate reservoirs.

7.3 Recommendations

1. To study EM heating for heavy oil recovery, the microwave source was converted into a heat source using equations that were a function of absorption coefficient. To study the actual mechanism, simulating microwaves with fluid flow would give more accurate results.

2. The reservoir was assumed to be saturated only with oil phase. But in actual cases water may be present. The presence of water can affect EM heating. With water present, heating converts water into steam that condenses and aids further heating. Hence the presence of water poses a complex multiphase modeling. The presence of water also affects the permeability of oil. A study should be done taking into consideration the presence and movement of connate water.

3. The reduction in viscosity achieved due to EM heating was based on the correlation used as shown in Equation 2.4. Different oil samples have varying reduction in viscosity with temperature. Also the viscosity reduction with increasing temperature depends on the equation used. An analysis should be done using different correlations

that would give different results in viscosity reduction and hence different oil production rates.

4. Power in case of EM heating is transmitted downhole through an antenna. The energy calculations used in this work did not include the efficiency of the antenna and also the power losses that take place while transmitting EM waves through it. Further work needs to be done taking into consideration these two factors that might affect the results.

5. The reservoir was considered to be homogeneous, but reservoir heterogeneity can affect the flow of fluids and cumulative oil produced.

6. Heat loss to the overburden and under-burden was not considered. Heat loss in actual field applications can be significant.

7. Low frequency electrical heating depends on the presence of connate water for electric current conduction and thus heat generation. Due to reservoir heterogeneity, the water path may not be continuous and might result in an incomplete path for the electric current.

8. The electrical conductivity of hydrates, which can also affect resistive heating, was not considered for this work.

9. Electrical conductivity is a function of temperature, but for this work it was assumed to be constant. A study of heating that considers the variation of conductivity with temperature might give more accurate results.

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APPENDIX

a) Specific heat capacity of oil, C_{po} = 4,457 J/Kg-K

b) Thermal conductivity of oil, K_o = 0.445 W/m-K

c) Specific heat capacity of formation, C_{pf} = 837 J/Kg-K

d) Thermal conductivity of formation, K_f = 5.573 W/m-K

e) Compressibility of oil, C_o = 1.5E-5 1/psi

f) Compressibility of formation, C_f = 15E-6 1/psi

g) Energy calculation for EM heating process

$$P = E / T \tag{A-1}$$

Where,

P = Power (Watts)

E = Energy (Joules)

T = Time (Seconds)

Power = 70,000 W

Time = 3 years

= 94608000 seconds

Therefore,

Energy (J) = 70,000 (W) * 94608000 (Sec)

= 6.6225 E+12 Joules

= 6,276 MMBTU

h) Steam injection calculation for CSS process

$$Q = \dot{m} * H_s * t \tag{A-2}$$

Where,

Q = Energy injected, BTU

$\dot{m}$ = Injection rate, lbm/hr.

H_s = Energy content of injected steam relative to initial reservoir temperature, Btu/lbm.

t = time period of injection, hr.

H_t = 977 Btu/lbm. (Green and Willhite, 1998)

t = 1,680 hrs.

Q = 6,276 MMBTU

Therefore,

Rate of steam injection = 26,765 lbm/hr.

Rate of steam injection = 260 bbls/day.

Table A.1 Relative permeability data used for CSS model in CMG-STARS (After CMG Template File)

S_w	K_{rw}	K_{row}
0.45	0	0.4
0.47	5.6E-05	0.361
0.5	0.00055	0.30625
0.55	0.00312	0.225
0.6	0.00861	0.15625
0.65	0.01768	0.1
0.7	0.03088	0.05625
0.75	0.04871	0.025
0.77	0.05724	0.016
0.8	0.07162	0.00625
0.82	0.08229	0.00225
0.85	0.1	0

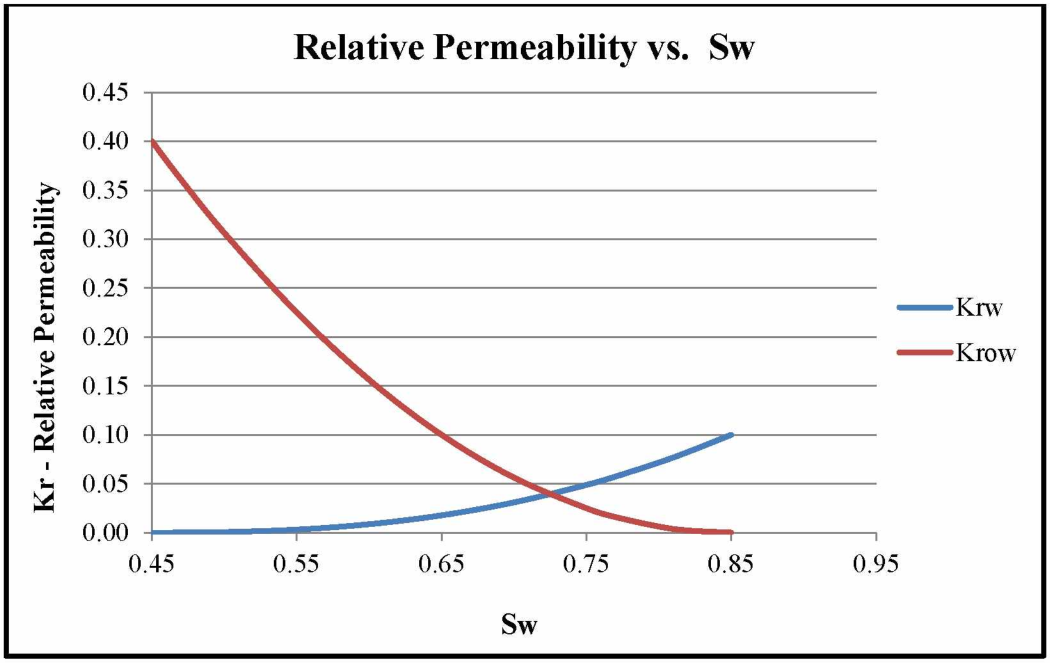

Figure A.1: Relative Permeability Plot used for CSS in CMG-STARS